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The Estimated Recovery Potential of Conventional Source Domestic Crude Oil

Mathematica, Inc, Philadelphia, Pa

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THE ESTIMATED RECOVERY POTENTIAL OF CONVENTIONAL SOURCE DOMESTIC CRUDE OIL

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By
J.W. Devanney III*
R. Ciliano
R.J. Stewart*

Prepared for
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Contract No. 68-01-2445

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May 1975

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* Martingale Assoicates; Cambridge, Massachusetts

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Dr. J. W. Devanney and Mr. R. J. Stewart of the Martingale Associates developed and implemented the models and methodologies from whose application the bulk of the cost-performance and recovery analysis derived. Both Dr. Devanney and Mr. Stewart also serve on the faculty of M.I.T.'s Department of Ocean Engineering.

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NOTE

This report has been reviewed by the Office of Policy Planning, EPA, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Environmental Protection Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

ABSTRACT

Approximately 350 of the 60,000 oil reservoirs in the United States account for over 60% of the domestic crude production to date, 75% of the API designated recoverable reserves and over 63% of the already discovered remaining oil in place. Even within these, the distribution of volume is highly skewed toward the 100 largest fields. Because prospective future additions to domestic crude supply from yet-to-be-discovered onshore Lower 48 deposits should prudently be viewed as marginal, at best, secondary and tertiary recovery potential from existent giant fields takes on increased significance.

This report describes a comparative assessment of alternative oil recovery techniques performed under Contract 68-01-2445 with the Environmental Protection Agency's Office of Policy Planning. A major objective of this study is to advise the EPA and in turn other Federal agencies on the extent to which changes in these techniques can plausibly be expected to stimulate additional production from already discovered reservoirs.

The vast bulk of prior studies which have focused upon this issue has simplistically attempted to extrapolate past performance at an aggregate national level. Here alternatively, the attempt was to construct a supply curve of domestic crude predicated upon a range of physical reservoir characteristics, the distribution of remaining oil-in-place, and various costs and constraints which influence the application of secondary and tertiary methods subsequent to primary recovery operations.

The study is generic in nature in that it does not appraise specific field or reservoir potentials, nor does it concern itself with the current or contemplated efforts of specific operators. Rather, it descirbes particular states of technology and economy under which specific techniques appear to dominate for reservoirs categorized into several classes by various physical descriptors (formation type, permeability, viscosity, porosity, etc.). Estimating the total size (remaining oil-in-place relative to original oil-in-place and the production history-to-date) of each reservoir class provides a basis for determining a plausible level of incremental supply that may be forthcoming under the attendant set of conditions associated with that class of reservoir and the technique(s) which appear most suited to it.

Secondary methods analyzed are immiscible gas injection and waterflood. Tertiary methods included polymer thickened waterflood, hydrocarbon miscible, CO_2 and inert gas miscible, miscible micellar, surfactant flood, solvent soak, wettability agents, steam soak and full steam drive and in-situ combustion (fireflood).

A data base was compiled on over 350 major domestic oil fields with information gathered from a comprehensive literature analysis, field trips to state regulatory agencies and actual project sites, as well as extensive interviews and discussions with petroleum industry personnel. The data files contain such

information as estimates of reservoir discovery date, depth, acreage, thickness, type of trap, type of rock, primary drive mechanism, secondary drive mechanism, tertiary drive mechanism, oil gravity, sulphur content, absolute permeability, porosity, percentage connate water, original oil-in-place, estimates of current oil saturation, regionally estimated original oil-in-place, OGJ estimated recoverable reserves, cumulative crude production to January 1, 1973, volumetircally estimated original oil-in-place and a "best estimate" of remaining oil-in-place. In addition, corresponding cost and operational performance data were collected on both active and abandoned recovery projects.

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I. SUMMARY AND OVERVIEW

Background and Perspective

This report describes the results of a preliminary attempt to assess the feasibility of utilizing physically based procedures to derive estimates of domestic crude oil supply from conventional recovery methods. Given the inherent degree of uncertainty with respect to yet-to-be discovered oil, the report focuses primarily upon the prospects for additional oil recovery from already discovered reservoirs.

The motivation behind this work should be quite obvious. Of the estimated 450 billion barrels of oil-in-place (OIP) which has been discovered to date in the United States, only about 106 billion barrels have been produced. A question of immediate interest, then, is how much of the remaining oil can be recovered and at what cost. In other words, what is the likely supply curve for this oil?

The answer to this question will depend largely upon the characteristics of this oil *in situ*; most importantly viscosity, permeability, current oil saturation, and depth.

Surprisingly enough, an estimate of a domestic supply curve of already-discovered oil based on geological reservoir characteristics appears never to have been attempted.[1] Those reported non-industry supply analyses of which we are aware base their forecasts simply on more or less sophisticated projections of past experience. With respect to yet-to-be discovered oil, there is little lattitude for doing otherwise. However, with respect to already-discovered petroleum, it appears strange to employ methods which make no explicit use of what we already know about the critically important characteristics of the remaining oil and gas in place.

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[1] Though, as discussed below, reservoir simulation techniques have been applied to assess recovery potential from specific reservoirs in specific fields, one could in no way term these limited applications as attempts to derive a supply curve.

Industry-generated studies tend to take more cognizance of reservoir data but, unfortunately, they have tended to be of two types:

- overall pronouncements based largely on the subjective judgment of a presumably knowledgeable individual or committee;
- extremely detailed project-by-project analyses of specific reservoirs aimed toward investment decisions relative to increased recovery projects in particular fields.

Between these two extremes exists a conspicuously large gap. Given the structure and organizational objectives of the petroleum industry, its lack of initiative in closing this gap is understandable. Unfortunately this breach must be filled if reasonably reliable estimates of the response of production from already-discovered reservoirs to changes in price are to be made. This study makes a positive initial attempt in that direction.

Secondary and Tertiary Recovery

The Methods Defined

The definition of enhanced recovery methods as used, for example, by the oil and gas regulatory bodies of the 30 states comprising the Interstate Oil Compact, is production of crude oil from reservoirs through actions taken to increase primary reservoir drive via pressure maintenance, waterflooding, gas injection, miscible fluid displacement, microemulsion flooding, in-situ combustion, cyclic steam injection, steam flooding, CO_2 injection, polymer flooding, caustic injection, or other related methods.

For our purposes, we have arbitrarily defined in our report secondary recovery methods as immiscible gas injection and water flood or combinations of both. The major tertiary methods we have defined as

- hydrocarbon miscible
- CO_2 and inert gas miscible

- micellar miscible
- steam drive (cyclic and full flood)
- in-situ combustion ("fireflood").

These methods will be discussed in great detail in subsequent sections. Essentially, however, the secondary methods are aimed strictly at maintaining reservoir pressure at levels adequate to prevent production cut-off beyond the point at which the reservoir's inherent driving forces cease to be effective. Given that beyond a certain point 50% or more of the original oil may still be in place for a typical reservoir undergoing pressure maintenance, there has been considerable interest in methods which go beyond secondary recovery. These methods attempt not only to apply pressure to the oil but also to alter the forces which hold the oil in place. The major tertiary methods fall into two basic categories:

- miscible methods aimed at reducing the surface tension forces between the oil and the driving fluid;
- thermal methods which are aimed at reducing the viscosity of the oil by heating as well as in some cases changing the chemical character of the oil.

It is the assessment of both the technological and economic feasibility of applying these secondary and tertiary methods, given the in-situ characteristics of remaining oil volumes, which comprises the bulk of this report's content.

Relative Importance of Enhanced Recovery Methods

In 1973 the United States total average daily crude oil production was approximately 9.2 million barrels per day.[1] Of this, approximately 41 percent or 3.8 million barrels per day was produced by enhanced recovery methods.[2] Of the 3.8 million barrels per day from enhanced production projects, approximately 13 percent or 476 thousand barrels per day was produced from projects whose average daily production per well was less than 10 barrels. Individual wells producing at this rate are classified as "stripper wells."

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[1] See "Enhanced Recovery Alternatives" (published under FEA contract C-05-50130-00); The Interstate Oil Compact Commission, Tulsa, Oklahoma; 1975. See Chapter V for a summary of this data.

[2] An additional 1.8 million barrels of natural gas liquids were produced daily, on average, during 1973. This production, a useable substitute for crude oil in many processes, is not generally subject to enhanced recovery methods. Consequently, these statistics relate to crude oil only.

U.S. domestic crude oil production during 1974 was estimated to be approximately 8.9 million barrels per day, a net decline of approximately 340 thousand barrels per day over the 1973 average daily production. However, a larger gross decline was partly offset by increases in production from enhanced recovery projects initiated in 1970 and earlier. There were 12 states with increases in production from such projects. The total of those increases was about 97,500 barrels daily.

Based on the data provided by a parallel study also undertaken by the Interstate Oil Compact Commission (IOCC) and its member states, it was estimated that there are approximately 9,000 existing enhanced recovery projects. They have over 125 thousand producing wells and had an estimated 14.6 billion barrels of proven recoverable oil remaining as of December 31, 1974. Of this 14.6 billion barrels of recoverable oil remaining, approximately 79 percent is associated with pressure maintenance, waterflooding and cyclic steam injection projects. The remaining 21 percent is associated with other "more exotic" enhanced recovery projects.[1]

The IOCC estimates that during the 1975 to 1980 period as many as four thousand (4,000) additional enhanced recovery projects may be initiated. The corresponding increase in ultimate recovery of crude oil resources associated with these enhanced recovery projects will be affected by additional capital investment in existing and new enhanced recovery projects. Also important in the increase are changes in the economic life of existing recovery projects.

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[1] Ibid. Resource Analysis & Management Group analysis of data provided through the Interstate Oil Compact Commission and the compacting states regulatory bodies. Resource Analysis and Management Group is a private contract research organization. Refer also to discussions in Chapter V.

The increase in ultimate recovery of crude oil from new and existing enhanced recovery projects between 1975 and 1980, at a crude oil price of $10.00 per barrel, is estimated by IOCC as approximately 10 billion barrels. Of this 10 billion barrels, approximately 10 percent comes from the extension of economic life of existing projects and 90 percent from capital investment in new and existing projects.[1]

Though our estimates of increased ultimate recovery (as summarized in the next section and discussed at length later in the text) do not precisely match those of IOCC, nonetheless the important common conclusions are that enhanced recovery methods:

- do offer significant potential for augmenting future crude supplies from conventional sources;
- contribute to the national priority goals of energy conservation and efficient resource exploitation;
- impact favorably upon the movement towards reduced domestic dependence on foreign imports with its attendant security and balance of payments implications;
- offer an immediate alternative to other energy development options whose technological, environmental, and financial risks are sufficiently undefined so as to create considerable apprehension.

Preview of Major Research Results

Our preliminary analysis which examined characteristics of the 350 largest fields in the United States (which hold approximately 63% of API's estimated total of 450 billion barrels of already discovered original oil-in-place) suggests that the present range of prices may induce as much as fifteen billions barrels more oil out of present reservoirs than is currently included in A.P.I. recoverable estimates and quite likely no more than 25 billion barrels. Furthermore, even rather substantial increases in price above current levels are unlikely to have a large incremental effect on overall recovery. These incremental recovery volumes are summarized in Figure I-1. The basis for these estiamtes will be discussed in detail in subsequent sections. It is interesting to note that while our results are pessimistic with respect to enhanced recovery being a major factor in our hopes to achieve domestic self-sufficiency, our"high range"estimates are probably overly optimistic in that some of the more exotic methods were given "every benefit of the doubt" with regard to their potential for application. As we will examine later, it is satisfying to note that the IOCC estimate of enhanced recovery from remaining oil-in-place[1] coincides very closely with our "low range" estimate and ironically enough, appeared in the Oil and Gas Journal less than one week after the submission of our Draft Final Report to EPA.

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[1] IOCC, op.cit.

Organization of the Report: A Quick Tour

In Chapter II we set the stage by addressing the problem of yet-to-be-discovered oil. This chapter consists of a critique of the projections of this random variable which have appeared in the literature together with the results of analyses based on a fairly comprehensive oil field development model. The latter exercises indicate, as we shall expand on later, that the bulk of whatever primary oil is found will be quite inexpensive in terms of resource cost to the nation compared with the current landed cost of imported crude.

Chapter III discusses the comprehensive survey of existent literature conducted as a prelude to our current effort as well as the compilation of the "Big Fields" data files which contain major reservoir characteristics of a sample of 350 of the largest fields in the United States. It is in this chapter we illustrate how combinations of characteristics were categorized so as to provide "partitions" of the remaining oil-in-place most compatibly suited (in a physical sense) to each of the various recovery methods.

FIGURE I-1

PRELIMINARY ESTIMATES OF INCREMENTAL ENHANCED RECOVERY OF REMAINING OIL-IN-PLACE AS OF 12-31-74*

Method of Recovery	Low Range** Estimate (10^9 BBLS)	High Range*** Estimate (10^9 BBLS)
Extended Waterflood	*8.00*	*9.00*
Thermal (primarily steam, cyclic and flood)	*4.25*	*9.75*
Micellar and hydrocarbon miscible	*0.25*	*2.50*
CO_2 and inert gas miscible	*2.50*	*3.75*
TOTAL	*15.00*	*25.00*

*assumes lifting of current two-tier FEA "old-new" price regulation; otherwise assumes existing tax and cost treatment policies.

**free market prices in $8-12 range.

***free market prices in $12-16 range.

Chapter IV describes each of the recovery methods and discusses associated technological and economic facets of their application and the basis for projecting their potential.

Chapter V summarizes the major findings of the study and briefly compares some of the more important results with other recent research efforts. In assessing these results it may be useful for the reader to know that the authors of this report entered into this study accepting the conventional wisdom--conventional that is, outside the oil industry--that the API recoverables estimate was an economically meaningless figure, insensitive to price change, subject to extended lags and as such, hopelessly conservative. Our admittedly preliminary investigations indicate otherwise.

II. YET-TO-BE-DISCOVERED OIL

Potential Discoveries: Onshore Lower 48

The Resource Base

Nobody knows precisely how much oil will be found in the future. Nonetheless, it is interesting to review the arguments which have been made relative to this random variable if only to place bounds on our range of uncertainty. The specific question of how much oil remains to be found onshore in the Lower 48, is currently a matter of heated controversy. The U.S. Geological Survey (U.S.G.S.) has officially estimated[1] undiscovered recoverable reserves at between 110 and 214 billion barrels[2]. The National Petroleum Council (NPC) correspondingly estimates this range as 53 to 70 billion barrels.(3) A Mobil Oil Corporation analysis placed recoverables at approximately 13 billion barrels. A prior study by M. K. Hubbert, a U.S.G.S. geologist, estimated only 9 billion barrels recoverable. In short, the present estimates vary by as much as a factor of 25 which is hardly encouraging. See Figure II-1 for a comparison of updated U.S.G.S. and Mobil estimates.

Yet-to-be-discovered oil is not the main thrust of this effort and there is little of substance we can add to this controversy. However, it is our opinion that Hubbert is closer to the truth than is the U.S.G.S. The U.S.G.S. figures were obtained by estimating, by region, the volume of prospective sediments and applying a productivity factor in barrels per cubic mile of sediments to this volume. This factor was based on either observed productivity in the explored area within the region (or in geologically similar basins elsewhere) adjusted by the regional geologist's judgment. Hubbert's results, on the other hand are based on a projection of the historical trends in discovery rates per foot of well drilled which have

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[1] This and all subsequent references will either be indicated by a numeral enclosed in brackets corresponding to bibliography entries or described in footnotes which immediately follow on the same page.

FIGURE II-1

OIL AND GAS RESOURCE ESTIMATES*

Location	Undiscovered Recoverable Oil and Natural Gas Liquids		Undiscovered Recoverable Natural Gas		
	Mobil Expected Value	U.S.G.S. Low Value	Mobil Expected Value	U.S.G.S. Low Estimate	Potential Gas Committee
	billion bbl		trillion CF		
Onshore					
Alaska	21	25	104	105	140
Lower 48 States	13	110	65	500	550
Subtotal Onshore	34	135	169	605	690
Offshore					
Atlantic	6	10	31	55	35
Alaska	20	30	105	170	226
Gulf of Mexico	14	20	69	160	184
Pacific Coast	14	5	69	10	11
Subtotal Offshore	54	65	274	395	456
Total U.S.	88	200	443	1000	1146

*Source: Adapted from Gillette, R., "Oil and Gas Resources: Did USGS Gush Too High?" Science 185, page 128; July 12, 1974.

fallen by an order of magnitude over the last 50 years, despite revolutionary advances in explortion technology in that period.

Inspection of these estimates emphasizes the dramatic extent of disagreement relative to the amount of oil and gas that remains to be discovered in the Lower 48 States. The Mobil Oil "expected value" for oil in the Lower 48 is 13 billion bbl, one-eight of the U.S.G.S. low estimate of 110 billion bbl. For potential gas, the Mobil Lower 48 figure of 65 trillion CF is also about one-eight of the U.S.G.S. and Potential Gas Committee estimates of 500 and 550 trillion CF, respectively.

Considerably different methodologies are used by Mobil Oil and the U.S.G.S. to derive their figures. Mobil Oil uses a computer program to combine the geologic and production characteristics of known and possible oil and gas reservoirs. The subjective judgment of field exploration personnel is used as an input to the computer program. The program then derives a "probability profile" of known and suspected oil and gas deposits in the 14 oil provinces in the U.S. For example, the Mobil technique predicts a 90% probability that the amount of undiscovered recoverable oil and natural gas liquids in the U.S. is between 50 and 150 billion bbl, the expected value being 88 billion bbl.

The U.S.G.S. method consists of the determination of the amount of unexplored sedimentary rock and the prediction of the potential oil and gas based on historical finding rates. In 1960, A.D.Zapp of the U.S.G.S. estimated that 80% of sedimentary rock in the U.S. was unexplored. Therefore, the 80% of unexplored rock should yield about 4 times as much oil and gas as had been found. In 1962, M. King Hubbert, also of the U.S.G.S. pointed out, however, that Zapp's approach implied a uniform finding rate per foot of exploratory wells drilled, but that in actuality, the finding rate was decreasing. (The late 1930s finding rate of 276 bbl of oil/foot of exploratory drilling had declined to 30 bbl/foot in 1972.) In 1965, the U.S.G.S. revised its earlier estimates and assumed that half as much oil would be found in unexplored rock as in explored rock. Hubbert maintains that based on current finding rates, the U.S.G.S. estimate is still 5 times too high for onshore terrain, and his latest figures agree with the Mobil Oil projection.[1]

The U.S.G.S., however, maintains that the Mobil Oil approach reflects a major oil company tendency to look for large oil and gas fields and ignores the potential of smaller deposits of oil and gas, which could, in total, add up to very large reserves.

Looking specifically at several other features of the projection, Mobil predicts much lower potential gas reserves in the Gulf of Mexico than the U.S.G.S., but a much higher potential on the Pacific Coast. The U.S.G.S. projected gas/oil ratio on the Pacific Coast is 2000 CF/bbl, whereas the Mobil ratio is 4900 CF/bbl, implying that the area is much more gas-rich than has previously been postulated. Interestingly, the Pacific Coast is the only area where Mobil projects higher potential oil reserves than the U.S.G.S.

It is interesting to note the American Gas Association's commentary on the Mobil estimate:[2]

> The immediate reaction to Mobil's estimate is likely to be one of consternation, since the availability of indigenous oil and gas plays a large role in the formulation and implementation of our national energy policy. It is necessary, however, to place such forecasts in proper perspective. First, of course, the accuracy of any forecast can only be established by future experience. We should recall that up until the early 1960s the U.S.G.S. was severely criticized for underestimating national resources. During recent years, some have complained that its estimates were too high. As noted above, its most recent low estimate for gas is essentially the same as the Potential Gas Committee's. Also, since the membership of the Potential

---

[1] For further background, refer to Proceedings of the AAPG Research Symposium: Methods of Estimating the Volumes of Undiscovered Gas and Oil Reserves; Stanford University; Palo Alto, Cal.; Aug. 1974.

[2] A.G.A. Gas Supply Review; Vol. 2, No. 10, July 15, 1974. (Published by IGT, Illinois Institute of Technology; Chicago, Ill.).

> Gas Committee includes all of the major oil companies, it would seem that Mobil's gas projection for the Lower 48 onshore region does not necessarily reflect the opinion of other qualified experts in gas exploration and development.
>
> Another large unknown is the extent to which subjective economic judgment was applied to the Mobil estimates of gas reserves. If a wellhead price of 26 cents/1000 CF was tacitly assumed in the estimating process, then perhaps the Mobil figure for potential gas in the Lower 48 is valid. On the other hand, an assumed future wellhead price of, say, $1.00/1000 CF might have resulted in considerably higher figures. In balance, the Mobil Oil effort should be taken into consideration along with other forecasts in evaluating potential oil and gas supplies, but the inherent risks and unknowns associated with all such forecasts should be kept clearly in mind.

Also, the U.S.G.S. methodology is inherently optimistic in that it ignores the fact that the best prospects are usually drilled first. Occasionally, the U.S.G.S. contributors have used a productivity factor for a large basinal area which was a fraction (typically 25%) of the productivity factor of the area which had been explored by drilling. Even this appears optimistic when one realizes that 71% of all the oil which has been found in the United States has been discovered in structural traps and that very few large structures at oil bearing depths (15,000 feet or less) have not been drilled. Often the U.S.G.S. regional editors would treat areas which had not been subject to intensive drilling as completely unexplored despite the fact that the area had been initially explored by geographysical methods and considerable effort had gone into looking for conditions which would be favorable to stratigraphic traps.

The U.S.G.S. methodology also ignores the fact that most of the oil which has been found in the United States (and the world, for that matter) has been found in a few, very large fields. As we shall discuss in later sections, 250 of the more than 60,000 reservoirs in the United States account for over 65% of domestic production to date, 75% of the API recoverable reserves and over 60% of the already discovered remaining oil in place. Even within this sample of large fields, the distribution of volume is highly skewed toward the 100 largest fields. The selected fields shown in Figure II-2 represent close to 50% of the remaining recoverable reserves according to Oil and Gas Journal estimates. One field, Prudhoe Bay, represents close to 25% of remaining recoverable reserves.

Less than one tenth of one percent (0.1%) of domestic fields account for 50% of our reserves. The reason is simple. The range of domestic field sizes in terms of original oil in place (OOIP) runs from about 20 billion barrels to fields of a few hundred thousand barrels or less--over four orders of magnitude. In short, one very large find can be worth literally thousands of small finds.

Furthermore, large fields are, in general, easier to find than small ones. History bears this out. The average year of discovery of the sample of 250 very large Lower 48, onshore fields (described in Chapter III) is 1926. In the last decade, there have been only four oil fields found onshore in the Lower 48 which have estimated OOIP greater than 100 million barrels.[1] These are shown in Figure II-3.

Prospects for Discovery: The Road Ahead

In 1973 despite an all time record for wildcat footage drilled as well as a near record 701 wildcat successes (a sure sign of technological improvement) not one field found was rated at more than 25 million barrels of oil reocverable.

It is important to recognize that for a long time market prices have been such that the discovery of even a rather marginally sized field of, perhaps, 10 million barrels was an extremely profitable venture. And if one got lucky and discovered a Bell Creek, where the unit cost of production

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[1] Future revisions and extensions may add 1 or 2 more fields to this list.

FIGURE II-2

DOMESTIC LOWER 48 OIL FIELDS: SELECTED "SUPER- GIANTS"[6]

(All volumes MMBBLS)

FIELD	DISCOVERY DATE	REMAINING RECOVERABLE OIL-IN-PLACE (RROIP) OGJ[1]	API[2]
Prudhoe Bay	1968	9600[3]	9600
Santa Ynez	--	2000-3000[4]	--
East Texas	1930	1800	1300
Yates	1926	1000	1400
Elk Hills	1919	1000[5]	705
Kern River	1899	850	250
Wilmington	1932	700	705
Wassan	1936	630	636
Kelly-Snyder	1948	500	477
Midway Sunset	1894	420	303
Hawkins	1940	300	305
West Ranch	1938	300	96
Slaughter	--	--	350
Tim O'Connor	--	--	315
Shovelton	--	--	297
Jay	--	--	267
Hastings	--	--	253
McArthur River	--	--	250
Webster	--	--	226
Caillow Island	--	--	205
Rangely	--	--	194

Notes:

1. Oil and Gas Journal estimates.
2. American Petroleum Institute estimates.
3. Unofficial reports set recoverables at 12.5 billion bbls.
4. Not yet entered in reserves estimates.
5. Includes U.S. Naval reserves.
6. The 100 largest domestic fields contain 24.3 billion (71%) of the 34.2 billion barrels RROIP as estimated by API. However, these fields account for only about 53.1% of the average daily domestic production of about 8.9 MMBPD.

(before royalties and taxes) was less than 20¢ per barrel, then even at oil prices of $2-3 per barrel, one had a veritable bonanza.[4] Given this situation, it was simply "good oil sense" to intensively explore even rather low probability prospects. For instance, there have been 506 recorded exploratory wells drilled in South Dakota. All this effort has discovered two oil fields with a total of 18 million barrels in place.[5]

Kaufman[6] has developed an oil discovery model based on the premises that:

(i) we are sampling without replacement from a finite population;

(ii) the probability that a given remaining field in the population will be found next is proportional to the size of the field;

(iii) oil field sizes are distributed according to an exponential process.

One interesting and sobering result of this model is that the mean size of the fields to be found decreases linearly with the number of fields already found. While Kaufman's model at this point is still just a theoretical construct, in our opinion its premises are much more defensible than those of the U.S.G.S. which is tacitly assuming that "what we haven't drilled" is similar to "what we've already drilled."

Optimists with respect to the Lower 48 onshore potential normally base their optimism on either or both of two arguments:

- stratigraphic traps
- deeper drilling.

Present geophysical technology is not particularly adept at locating stratigraphic traps. Hence, the argument is given that if we obtain a breakthrough in technology, we might well find a great deal of stratigraphic oil. This is, of course, a possibility. To become a reality, two things are required: the advance in technology and the fact that there is a significant volume of oil in stratigraphic traps in the Lower 48 onshore which cannot be found by methods available in the past.

The technological advance may perhaps be near at hand. The use of digital amplifiers in seismic signal processing has extended the range of the recording system to the point where it is possible to identify anomalous amplitudes at a given depth. Where before the geologist had to be content with the knowledge that a difference in density existed at a given depth, he can now sometimes obtain an estimate of the magnitude of this difference. Since the difference in densities associated with petroleum, particularly gas, are typically larger than those associated with moving from one rock layer to another, anamolously large responses, known in the jargon as 'bright spots,' may be a direct indication of the presence of petroleum.

The efficacy of this bright spot technology may even now be relfected in the high wildcat success ratio we are presently enjoying. However, it is basically a gas oriented method which has yet to locate any sizable onshore oil fields. The next two or three years should yield more evidence concerning the potential of bright spot techniques and the likelihood of locating significant oil deposits in stratigraphic traps, at least those with gas caps.

Discoveries of deeper pays in known fields onshore in the Lower 48 totaled 172 million barrels of oil recoverable in 1973--a welcome, but not really significant, addition to domestic supply. The big problem with deeper exploration in already discovered structures, is that the corresponding increase in pressure and temperature imply that petroleum, if it is there, is much more likely to be gas. About 95% of all the oil which has been discovered in the United States is produced from reservoirs with depths less than 11,000 feet. While oil can exist in certain situations even at 20,000 feet, in general there is little prospect for oil much below 15,000 feet. Given the favorable economics discussed earlier, if a major structure has not already been drilled to 15,000 feet, in great likelihood there existed overriding geological or geophysical reasons for regarding the deeper areas as very low probability prospects. Though some oil will certainly be found in deeper pays, we feel we cannot be optimistic about the amount.

In summary, we believe it would be prudent to assume that the additions to domestic supply of yet-to-be-discovered oil in the onshore Lower 48, will be quite small relative to the volumes we will be discussing later in this report. Because of the size range of fields involved, a lot of small discoveries do not add up to a few big ones, and, in our opinion, there is a good chance that very few really large fields remain to be found in the onshore Lower 48.

Potential Discoveries: The Outer Continental Shelf and Offshore Alaska Shelf

The Resource Base

The prospects with repsect to yet-to-be-discovered oil in offshore Alaskan areas and the Outer Continental Shelf (OCS), are considerably different from those of the onshore Lower 48. Unlike almost all of the Lower 48 onshore petroleum provinces, large portions of Alaska and the OCS can reasonably be regarded to be truly unexplored. Hence, the U.S.G.S. method of applying average productivity factors to estimates of the volume of these sediments makes considerably more sense for these areas. As a result, there are somewhat smaller discrepancies among the various published estimates of yet-to-be-discovered oil for the

OCS and Alaskan shelf, than for the onshore Lower 48. These are shown in Figure II-4.

Some of these estimates have been further disaggregated by major region. These are shown in Figure II-5. Here, again, however, the range of estimation is still extremely large.

Prospects for Recovery

Though, as we state earlier, any estimate of how much oil will be found in the future is highly speculative, given the lack of exploration in these areas, we believe there is a good chance that the mid ranges, perhaps 60-80 billion barrels in primary yet-to-be-discovered oil, could be achieved.

The dominance of Alaska in these projections is a product of the size of the Alaskan shelf. The N.P.C. rates 582,000 square miles of the Alaskan shelf as oil and gas prospective as compared to 293,000 square miles of shelf area for the rest of the United States. The volume of sedimentary rock on the Alaskan continental shelf is estimated at 800,000 cubic miles: that for the rest of the OCS at 862,000 cubic miles. By comparison, the volume of sedimentary rock onshore in the Lower 48 is about three million cubic miles; that of onshore Alaska is listed at 215,000 cubic miles.

Again, we reiterate that our current effort was not aimed at estimating the inherently uncertain amount of oil remaining to be discovered. Rather, we have focused our attention on the question of determining the cost to the nation of landing whatever oil is discovered as a function of the location and characteristics of the find. That is, we will be discussing sets of hypothetical questions of the form: if you find a reservoir at "location x" in "water depth y" which contains "z barrels of oil" whose estimated permeability, porosity, and other descriptive characteristics are given, what then will be the corresponding cost of landing this oil in the Lower 48? We will want to ask such qeustions for a wide range of reservoir sizes, locations and geological characteristics.

FIGURE II-3

NEW GIANT OIL FIELDS DISCOVERED IN LAST DECADE

(All volumes MMBBLS)

FIELD	DISCOVERY DATE	ESTIMATED OOIP	CUM PROD. 12/74	ESTIMATED RROIP	
				OGJ	API
Jay	1970	700	75	312	343
Big Wells	1969	180	*	*	*
Bell Creek	1967	620	69	116	120
Black Lake	1964	100	*	*	*

*estimates unavailable

FIGURE II-4

ESTIMATES OF ULTIMATELY RECOVERABLE OIL VOLUMES

(All volumes in billions of barrels)

ESTIMATE	AREA	
	OCS & Alaskan Shelf	Alaska Onshore*
USGS (72)	206	--
N.P.C.	192	--
USGS (74)	65-130	25-50
Mobil Oil	54	21
Nelson & Burke	15-35	--
AAPG (Schmitt)	300	--
Hubbert	--	28

*Prudhoe Bay not included in volumes shown.

FIGURE II-5

DIS-AGGREGATED ESTIMATES OF ULTIMATELY RECOVERABLE OIL VOLUMES IN SELECTED REGIONS

Estimate / Area	Nelson & Burke	USGS (72)	USGS (74)	MOBIL	AAPG	WOGA
Atlantic OCS	0.5	48	10-20	6	5.5	--
Gulf of Mexico	--	50	20-40	14	--	--
Pacific OCS	--	9	5-10	14	--	6-19
Alaskan Shelf	--	62	30-60	20	--	--

*All volumes in billions of barrels.

The major tool we have used in performing these analyses is the Offshore Development Model.[1] The Offshore Development Model is a computer program, developed and refined over the last two years, which attempts to simulate the primary response of a given offshore reservoir to a specified development strategy. By iterating over alternative feasible strategies, the model seeks to identify that strategy which the profit maximizing developer would undertake together with the resulting financial and petroleum flows.

(i) The Offshore Development Model: General Logic

The Offshore Development Model takes as input three basic sets of variables: (a) geologic, (b) locational, and (c) financial/regulatory, as well as a number of program control variables and option codes. The geologic variables include such descriptors of the hypothetical find as oil-in-place, gas-in-place, type of drive, number of fields, field separation, depth, permeability, porosity, formation thickness, initial reservoir pressure and temperature, and gas and oil viscosity and density. A complete list of these input variables is given in Figure II-6.

Locational parameters include such variables as water depth, relevant distances to shore, and terminal draft limitations. A complete list of these input variables is given in Figure II-7.

Financial/regulatory variables include such parameters as landed price of oil and gas through time, cost of capital, lease payments, royalties, and oil and gas allowables (if any). Figure II-8 lists these input variables.

General program control variables are primarily concerned with computational options within the computer program. They include the minimum and maximum number of platforms per field which the user wants the program to consider, the minimum and

---

[1] The general logic of this program is described in the next section. A complete description of the model is given in Reference [7].

FIGURE II-6

OFFSHORE DEVELOPMENT MODEL

GEOLOGIC INPUT PARAMETERS: RESERVOIR CHARACTERISTICS

- Oil in place
- Gas in place
- Rock type
- Formation pressure
- Formation temperature
- Formation thickness
- Formation porosity
- Formation Permeability
- Pressure depletion increment
- Number of fields containing reserves
- Field separation
- Residual oil saturation
- Residual water saturation
- Oil API gravity
- Type of drive
- Gas viscosity
- Oil viscosity
- Kickout depth
- Depth to formation
- Drilling maximum slantangle
- Connate water
- Oil compressability
- Formation compressability
- Water compressability

FIGURE II-7

OFFSHORE DEVELOPMENT MODEL

LOCATIONAL INPUT PARAMETERS: TRANSPORT SYSTEM CHARACTERISTICS

- Tanker sea distance
- Refinery port draft limit
- Refinery port "lost" time
- Refinery port SBM distance to shore
- Refinery port SBM distance from refinery to shore
- Design wave height
- Transport Option Indicator
- Bottom Type
- Mobilization Distance
- Oil pipeline sea distance
- Oil pipeline land distance
- Gas pipeline sea distance
- Gas pipeline land distance
- Refinery port terminal building option
- Pipe yield stress
- Maximum pipe wall thickness
- Weather down time

FIGURE II-8

OFFSHORE DEVELOPMENT MODEL

FINANCIAL/REGULATORY INPUT PARAMETERS: ECONOMIC CHARACTERISTICS

- Investor's cost of capital
- Borrowing interest rate
- Debt/equity ratio
- Fraction of pre-lease bid profits bid away
- Steel cost
- Maximum number of platforms which can be installed in a year
- Yearly landed oil price
- Yearly landed gas price
- Initial production year (relative to 1972)
- Oil allowable (if any)
- Gas allowable (if any)

maximum number of wells per platform to be considered, the maximum number of pump/compressor platforms and an option which specifies whether oil and gas pipelines have the same destination. The user can also specify that certain of the transport options not be considered. The general logic of the program is illustrated in Figure II-9.

Basically, the program examines a number of combinations of production schedule and transport system alternatives and chooses that combination which maximizes the developer's present valued profits. More precisely, the program takes as input one of the developer's key decision variables, amount of gas reinjection and then examines a range of number of platforms deployed and a range of number of wells per platform. These three decision variables, together with the reservoir's physical characteristics, determine a yearly oil and gas production schedule through time. This annual production stream is determined by a modified Muskat-Hoss gas drive reservoir model if gas solution drive is specified, and by an edge-drive infinite aquifer, Hrust-Van Everdingen/Tarner combination drive model if water drive is specified.

For each production schedule, the program examines a range of both tanker and pipeline systems for transporting the oil and gas to shore.[1] Tankers of 20, 30, 40, 80, 150 and 250 thousand deadweight tons are considered, subject to terminal draft limitations. Pipelines ranging from 8 to 48 inches in diameter are examined in approximately 4-inch increments combined with 1 to 5 pump/compressor platforms and 1 to 4 parallel lines which may come on stream at different times. That combination of "tanker and gas pipeline," "oil pipeline and gas pipeline," "oil tanker only," or "oil pipeline only" which maximizes present valued gross revenue

---

[1] The model operates under the assumption that gas can be transported to shore only by gas pipeline. Two-phase flow is not considered.

FIGURE II-9

OFFSHORE DEVELOPMENT MODEL

GENERAL PROGRAM LOGIC

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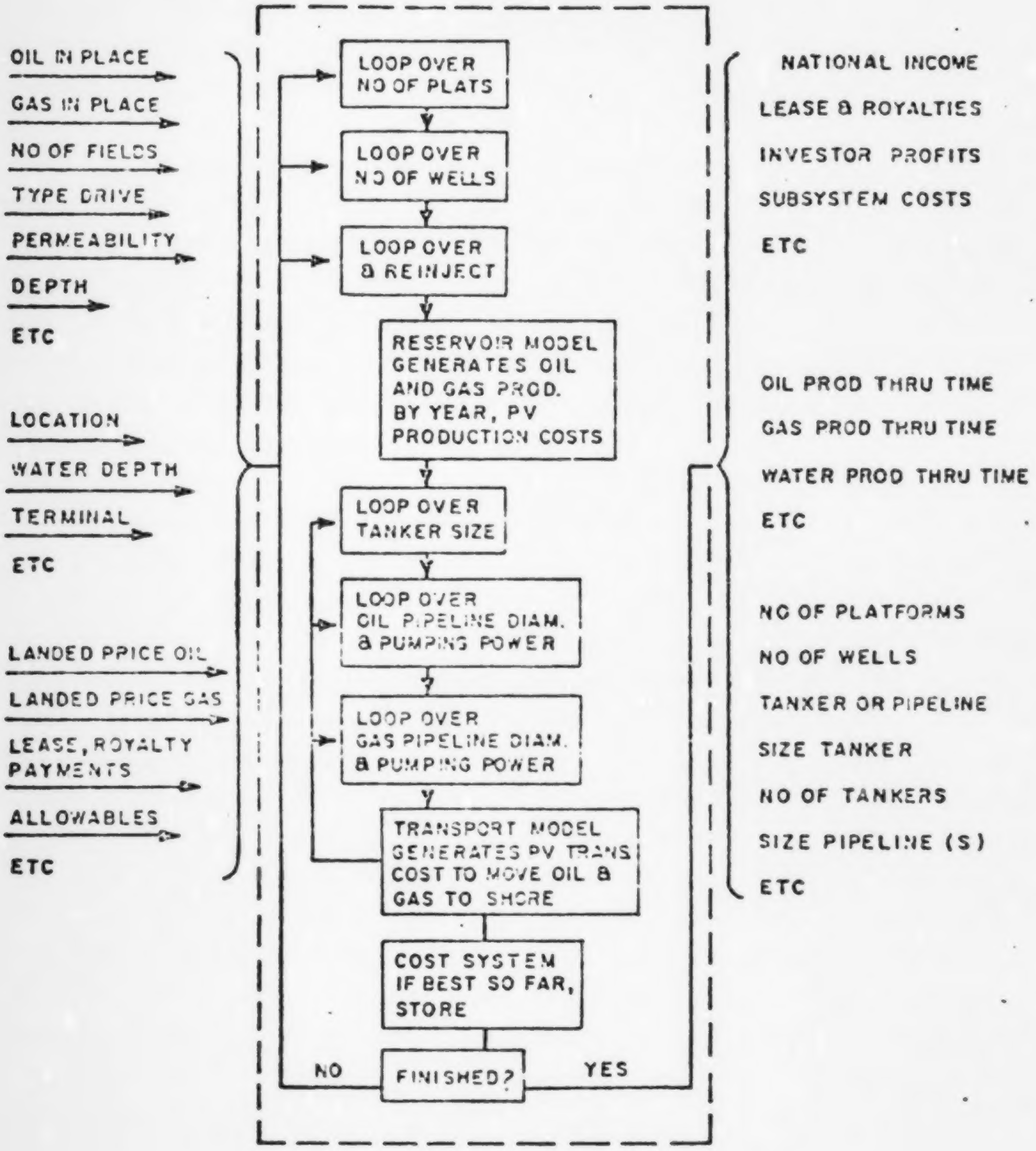
OIL IN PLACE
GAS IN PLACE
NO OF FIELDS
TYPE DRIVE
PERMEABILITY
DEPTH
ETC
LOCATION
WATER DEPTH
TERMINAL
ETC
LANDED PRICE OIL
LANDED PRICE GAS
LEASE, ROYALTY PAYMENTS
ALLOWABLES
ETC
LOOP OVER NO OF PLATS
LOOP OVER NO OF WELLS
LOOP OVER a REINJECT
RESERVOIR MODEL GENERATES OIL AND GAS PROD. BY YEAR, PV PRODUCTION COSTS
LOOP OVER TANKER SIZE
LOOP OVER OIL PIPELINE DIAM. & PUMPING POWER
LOOP OVER GAS PIPELINE DIAM. & PUMPING POWER
TRANSPORT MODEL GENERATES PV TRANS COST TO MOVE OIL & GAS TO SHORE
COST SYSTEM IF BEST SO FAR, STORE
NO
FINISHED?
YES
NATIONAL INCOME
LEASE & ROYALTIES
INVESTOR PROFITS
SUBSYSTEM COSTS
ETC
OIL PROD THRU TIME
GAS PROD THRU TIME
WATER PROD THRU TIME
ETC
NO OF PLATFORMS
NO OF WELLS
TANKER OR PIPELINE
SIZE TANKER
NO OF TANKERS
SIZE PIPELINE (S)
ETC

less transport costs is selected as the transport system for the particular production schedule under consideration.

This transport system and its cash flow are combined with the field capital and operating costs to generate all the cash flows associated with the combination of production schedule and transport system currently under analysis. The after-tax present valued profits are computed assuming a bonus bid equal to some fraction (user-specified, up to 99%) of his pre-lease payment, present valued after-tax profit (profit in excess of normal return on capital). This computation is done in two stages. First, the investor's present valued after-tax profit is computed assuming no lease payment. The investor's post-lease, after-tax profit is then set to a user specified fraction of this amount. The program then iteratively solves for the actual lease payment which will produce this difference in the investor's profit after taxes. Iteration is necessary since the tax stream will be affected by the presence of a lease payment.

The program then takes a user-specified proportion of the pre-lease payment profits and assumes that this percentage of the economic rent associated with the project is turned over to the federal government in the form of a lease bonus bid two years prior to initial production. The present valued profits after lease payment are then recomputed in their entirety, with the lease payment incorporated in the cash flow.

The user then may examine these results (the program is available on time sharing), modify the amount of reinjection as he desires and then repeat the entire evaluation process. Results of a sample run are given in Figure II-10 for purely illustrative purposes.

(ii) Application of the Model: Results of the Primary Recovery Anlaysis for Lower 48 OCS Areas

For the purposes of this study, a series of runs of the Offshore Development Model was made varying what appear to be the four key variables in determining the costs associated with developing a domestic offshore find. These are:

FIGURE II-10

THE OFFSHORE DEVELOPMENT MODEL:

ILLUSTRATIVE MODEL OUTPUT

```
**********************************************                         ***********************************************
**********************************************   SUMMARY OF C/   INPUTS   ***********************************************
**********************************************                         ***********************************************

STRATEGY VARIABLES:

MINIMUM NUMBER FIELD PLATFORMS USED.......      1             MINIMUM NUMBER WELLS PER PLATFORM USED...     24
MAXIMUM NUMBER FIELD PLATFORMS USED.......      9             MAXIMUM NUMBER WELLS PER PLATFORM USED...     24
FIELD PLATFORM INCREMENT FOR ITERATION....      1             WELLS PER PLATFORM INCR. FOR ITERATION...      4
MAXIMUM FIELD PLATFORMS ADDED PER YEAR....      5             MAXIMUM PUMP STATIONS ALLOWED (WATER)....      5
MAXIMUM PUMP STATIONS ALLOWED (LAND)......      0

RESERVOIR VARIABLES:

OIL IN PLACE.............................. 1,000 MMBBL        GAS IN PLACE.............................. 1,000 MMMCF
RESERVOIR TEMPERATURE.....................   200 DEG F        RESERVOIR INITIAL PRESSURE................ 5,000 PSIA
OIL ALLOWABLE PER WELL....................    10 MBPD         GAS ALLOWABLE PER WELL....................   100 MMCFPD
OIL API NUMBER............................30.000              GAS SPECIFIC GRAVITY...................... 0.600
OIL VISCOSITY............................. 2.000 CP           RESERVOIR POROSITY........................14.000 %
RESERVOIR ABSOLUTE PERMEABILITY........... 0.100 DAR          RESIDUAL (CONNATE) WATER SATURATION.......30.000 %
RESIDUAL OIL SATURATION--WATER FLOOD......20.000 %            RESIDUAL OIL SATURATION--GAS FLOOD........20.000 %
FRACTION OF EXPANDED GAS CAP PRODUCED.....20.000 %            MAXIMUM GAS REINJECTION................... 0.000 %
GAS SOLUTION DRIVE PRESSURE DECREMENT.....50.000 PSIA         WATER COMPRESSIBILITY (X 1000000)......... 3.200 /PSIA
OIL COMPRESSIBILITY (X 1000000)...........20.000 /PSIA        FORMATION COMPRESSIBILITY (X 1000000)..... 4.000 / PSIA
MODEL EMPLOYED............................WATER DRIVE         FORMATION ROCK TYPE.......................CEM. SS,OOLITE
NUMBER OF POOLS HOLDING RESERVES..........     1                                                        OR SMALL VUGS
FORMATION THICKNESS.......................    40 FT

FIELD VARIABLES:

DEPTH OF SEA OVER POOLS...................   252 FT           KICK-OUT DRILLING DEPTH (BELOW SEA FLOOR) 1,500 FT
DEPTH OF FORMATION (BELOW SEA FLOOR)......10,000 FT           DESIGN WAVE HEIGHT........................    40 FT
MAXIMUM DRILLING SLANTANGLE............... 0.785 RAD

TRANSPORT VARIABLES:

DISTANCE TO REFINERY PORT VIA SEA.........   146 MI           OIL PIPELINE DISTANCE--WATER ROUTE........   146 MI
REFINERY PORT DRAFT LIMIT.................    41 FT           OIL PIPELINE DISTANCE--LAND ROUTE.........     0 MI
SINGLE BUOY MOORING DISTANCE TO SHORE.....     0 MI           GAS PIPELINE DISTANCE--WATER ROUTE........   146 MI
SINGLE BUOY MOORING DISTANCE ON SHORE.....     0 MI           GAS PIPELINE DISTANCE--LAND ROUTE.........     0 MI
LOST MANEUVERING TIME IN PORT............. 0.850 DAYS         MAXIMUM PIPELINE WALL THICKNESS........... 0.750 IN
LAY BARGE & PLATFORM TOW DISTANCE......... 1,500 MI           YIELD STRESS OF PIPELINE STEEL............60,000 PSIA
REGISTRY OF TANKERS.......................   USA              TERMINAL CONSTRUCTION NECESSARY...........  NONE
BOTTOM TYPE...............................  SAND

FINANCIAL VARIABLES:

BASE STEEL COST...........................   200 $/TON        PLATFORM MOBILIZATION COST................     0 $000
OIL ROYALTIES............................. 0.120 $/BBL        DEBT TO EQUITY RATIO...................... 0.000
GAS ROYALTIES............................. 0.037 $/MCF        BORROWING INTEST RATE..................... 0.000 %
LEASE PAYMENT FRACTION OF PROFITS.........75.000 %            INVESTOR OPPORTUNITY COST OF CAPITAL......15.000 %
PERCENT BAD WEATHER DAYS PER YEAR.........10.000 %
OIL PRICE (1974).......................... 8.000 $/BBL        GAS PRICE (1974).......................... 1.500 $/MCF
```

FIGURE II-10

(continued)

THE OFFSHORE DEVELOPMENT MODEL:

ILLUSTRATIVE MODEL OUTPUT

```
       *********************************                                      *********************************
       ********************************* SUMMARY OF CAPITAL & OPERATING COSTS *********************************
       *********************************                                      *********************************

        <----------------CAPITAL COSTS---------------->   <---------------OPERATING COSTS--------------->
YEAR    FIELD     TANKER      OIL     GAS PIPE  GAS PIPE   FIELD     TANKER      OIL     GAS PIPE  GAS PIPE
        PROD     TERMINAL  PIPELINE   W/O OIL    W/ OIL    PROD       OPER    PIPELINE   W/O OIL    W/ OIL

1974  6.77E+07  3.31E+07  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00
1975  4.47E+07  0.00E+00  5.59E+07  4.36E+07  4.36E+07  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00
1976  5.22E+06  0.00E+00  3.45E+06  5.24E+06  9.16E+06  4.12E+06  1.86E+07  1.40E+06  1.09E+06  1.09E+06
1977  0.00E+00  0.00E+00  3.29E+05  0.00E+00  0.00E+00  4.14E+06  1.87E+07  1.48E+06  1.32E+06  1.32E+06
1978  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  1.35E+07  1.49E+06  1.32E+06  1.32E+06
1979  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  1.11E+07  1.49E+06  1.32E+06  1.32E+06
1980  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.79E+06  1.49E+06  1.32E+06  1.32E+06
1981  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.62E+06  1.49E+06  1.32E+06  1.32E+06
1982  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.54E+06  1.49E+06  1.32E+06  1.32E+06
1983  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.47E+06  1.49E+06  1.32E+06  1.32E+06
1984  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.36E+06  1.49E+06  1.32E+06  1.32E+06
1985  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.27E+06  1.49E+06  1.32E+06  1.32E+06
1986  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.25E+06  1.49E+06  1.32E+06  1.32E+06
1987  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.27E+06  1.49E+06  1.32E+06  1.32E+06
1988  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.26E+06  1.49E+06  1.32E+06  1.32E+06
1989  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.14E+06  1.49E+06  1.32E+06  1.32E+06
1990  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.13E+06  1.49E+06  1.32E+06  1.32E+06
1991  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.13E+06  1.49E+06  1.32E+06  1.32E+06
1992  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.14E+06  1.49E+06  1.32E+06  1.32E+06
1993  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.14E+06  1.49E+06  1.32E+06  1.32E+06
1994  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.07E+06  1.49E+06  1.32E+06  1.32E+06
1995  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.07E+06  1.49E+06  1.32E+06  1.32E+06
1996  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.08E+06  1.49E+06  1.32E+06  1.32E+06
1997  0.00E+00  0.00E+00  0.00E+00  0.00E+00  0.00E+00  4.14E+06  8.07E+06  1.49E+06  1.32E+06  1.32E+06
```

FIGURE II-10

(continued)

THE OFFSHORE DEVELOPMENT MODEL:

ILLUSTRATIVE MODEL OUTPUT

```
****************************
**************************** SUMMARY OF FIELD AND TRANSPORT PARAMETERS ****************************
****************************                                           ****************************

      TOTAL TOTAL    OIL         GAS        WATER      TANKER   NO.  NO.  CHARTER   OIL/  OIL/ GAS/  GAS/
YEAR  PLATS WELLS    PROD        PROD       PROD        DWT     TKR  TRPS  RATE    WATER LAND WATER LAND

1976    4     76  1.171E+08  9.127E+10  0.000E+00    40000     3   151  1.40E+07    1     0     1     0
1977    9    172  1.219E+08  8.459E+10  0.000E+00    40000     3   156  1.49E+07    1     0     1     0
1978    9    172  7.066E+07  5.217E+10  0.000E+00    40000     2   137  9.71E+06    1     0     1     0
1979    9    172  5.334E+07  4.571E+10  0.000E+00    40000     2   104  9.32E+06    1     0     1     0
1980    9    172  4.047E+07  4.043E+10  0.000E+00    40000     1   157  4.98E+06    1     0     1     0
1981    9    172  3.353E+07  3.800E+10  0.000E+00    40000     1   130  4.82E+06    1     0     1     0
1982    9    172  2.994E+07  3.747E+10  0.000E+00    40000     1   116  4.77E+06    1     0     1     0
1983    9    172  2.731E+07  3.727E+10  0.000E+00    40000     1   125  4.66E+06    1     0     1     0
1984    9    135  1.766E+07  2.572E+10  0.000E+00    40000     1    69  4.45E+06    1     0     1     0
1985    9    135  1.847E+07  2.676E+10  0.000E+00    40000     1    72  4.47E+06    1     0     1     0
1986    9    135  1.757E+07  2.596E+10  0.000E+00    40000     1    68  4.44E+06    1     0     1     0
1987    9    135  1.855E+07  2.817E+10  0.000E+00    40000     1    72  4.47E+06    1     0     1     0
1988    9    135  1.792E+07  2.907E+10  0.000E+00    40000     1    69  4.45E+06    1     0     1     0
1989    9    101  1.282E+07  2.022E+10  0.000E+00    40000     1    50  4.37E+06    1     0     1     0
1990    9    101  1.256E+07  1.866E+10  0.000E+00    40000     1    49  4.33E+06    1     0     1     0
1991    9    101  1.265E+07  1.833E+10  0.000E+00    40000     1    49  4.33E+06    1     0     1     0
1992    9    101  1.275E+07  1.809E+10  0.000E+00    40000     1    50  4.33E+06    1     0     1     0
1993    9    101  1.280E+07  1.785E+10  0.000E+00    40000     1    50  4.33E+06    1     0     1     0
1994    9     72  9.927E+06  1.339E+10  0.000E+00    40000     1    39  4.27E+06    1     0     1     0
1995    9     72  9.825E+06  1.214E+10  0.000E+00    40000     1    38  4.26E+06    1     0     1     0
1996    9     72  1.022E+07  1.202E+10  0.000E+00    40000     1    40  4.27E+06    1     0     1     0
1997    9     72  1.003E+07  1.180E+10  0.000E+00    40000     1    39  4.27E+06    1     0     1     0
```

FIGURE II-10
(continued)

THE OFFSHORE DEVELOPMENT MODEL:
ILLUSTRATIVE MODEL OUTPUT

```
***************************************                                  ****************************************
***************************************   MISCELLANEOUS SYSTEMS PARAMETERS  ****************************************
***************************************     AND PRESENT VALUE TOTALS        ****************************************
***************************************                                  ****************************************

OIL RECOVERY (%) ..............................   68.672     PV OIL PRODUCTION (SOLD MBBLS)..................   267,646
GAS RECOVERY (%)...............................   74.309     PV GAS PRODUCTION (SOLD MMCF)...................   233,677
OIL PIPELINE HORSEPOWER/STATION/LINE (WATER).     11,640     PV FIELD DEVELOPMENT COSTS ($000)...... ......   115,566
OIL PIPELINE HORSEPOWER/STATION/LINE (LAND)..          0     PV TRANSPORTATION COSTS--OPTIMAL ($000).......    97,023
GAS PIPELINE HORSEPOWER/STATION/LINE (WATER).     28,199     PV FEDERAL AND STATE INCOME TAXES ($000)......   870,311
GAS PIPELINE HORSEPOWER/STATION/LINE (LAND)..          0     PV LEASE PAYMENTS ($000).......................  1,072,128
OIL PIPELINE DIAMETER (WATER)..................       24     PV OIL ROYALTY PAYMENTS ($000)..................    32,117
OIL PIPELINE DIAMETER (LAND)...................        0     PV GAS ROYALTY PAYMENTS ($000)..................     8,762
GAS PIPELINE DIAMETER (WATER)..................       12     PV TOTAL NATIONAL COSTS ($000)..................   212,560
GAS PIPELINE DIAMETER (LAND)...................        0     PV INVESTOR PROFITS ($000)......................   287,171
BREAK-EVEN OIL PRICE-UNADJUSTED ($/BBL).......     0.796     PV GROSS REVENUES ($000).......................  2,491,690
BREAK-EVEN OIL PRICE-W/ LEASE & ROY ($/BBL)..      4.955     PV TANKER SYSTEM COST ($000)....................    86,424
BREAK-EVEN OIL PRICE-UNADJ LESS GAS PIPE $/B.      0.627     PV OIL PIPELINE SYSTEM COST ($000) ..........    51,827
BREAK-EVEN OIL PRICE-ADJ & NO GAS PIPE $/B...      4.786     PV GAS PIPELINE SYSTEM W/ TANKERS ($000).....    45,251
NUMBER OF PUMP STATIONS ON WATER ROUTE (GAS)              1     DISTANCE BETWEEN PUMP STATIONS (GAS/WATER)...   146.000
NUMBER OF PUMP STATIONS ON WATER ROUTE (OIL).             1     DISTANCE BETWEEN PUMP STATIONS (OIL/WATER)...   146.000
NUMBER OF PUMP STATIONS ON LAND ROUTE (GAS)..             0     DISTANCE BETWEEN PUMP STATIONS (GAS/LAND)....     0.000
NUMBER OF PUMP STATIONS ON LAND ROUTE (OIL)..             0     DISTANCE BETWEEN PUMP STATIONS (OIL/LAND)....     0.000
OIL SHIPPED VIA................................ PIPELINE

RESERVOIR MODEL COMPLETION CONDITION: INSTABILITY ON R_P
```

- Original Oil in Place (OOIP)
- Distance to Landing Point
- Water Depth
- Platform Design Wave Height.

Recall that the main purpose in exercising the model in the manner described earlier was to obtain not only the quantities of landed gas and oil but the corresponding prices (cost plus return) associated with those quantities as well. The transportation mode chosen between the wellhead and onshore terminal point is a very critical link in determining these total systems costs.

Thus the "locational" or transport system parameters were the primary focus of this particular analysis. The other major geological and financial variables were fixed at the values shown in Figure II-11. A complete list of the input values is shown in the sample run displayed in Figure II-10. These values define a rather average pure gas drive reservoir. Since in this section we are concentrating entirely on primary recovery, zero gas reinjection was specified in which case, according to the Muskat-Hoss model, the primary oil recovered is about 17% of the initial oil in place. Gas recovery is about 67%. In actual fact, as we shall see, such a field would be subject to considerable secondary effort which could easily double or triple this oil recovery. At this point, however, we are dealing strictly with primary oil.

The variables of direct interest to us in this section were iterated over the following values. Original oil in place was varied from 2 billion barrels down to 50 million barrels in the following steps: 2.0×10^9, 1.0×10^9, 0.5×10^9, 0.2×10^9, 0.1×10^9, 0.05×10^9. Distance offshore was varied from 25 miles to 75 miles to 150 miles[1] and in the case of Alaska, 1500 miles.

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[1] In some instances, such as California, distance offshore may be as small as 5 miles. The values chosen here, however, were meant to illustrate the sensitivity of this parameter over a range of variation corresponding to a reasonable likelihood of occurrence.

FIGURE II-11

OFFSHORE DEVELOPMENT MODEL

ASSESSMENT OF PRIMARY RECOVERY POTENTIAL

VALUES OF MAJOR INPUT PARAMETERS HELD CONSTANT DURING EVALUATION*

Type of drive	Solution Gas
Number of individual Reservoirs	1
Initial Gas/Oil Ratio**	100 :1
Reservoir Temperature	200°F
Initial Pressure	5000 psi
Formation Depth	10,000 Feet
Formation Thickness	40 Feet
Absolute permeability	100 md
Porosity	14%
Rock Type	Cemented Sandstone
Connate Water	30%
Oil API Gravity	30°
Gas Specific Gravity	0.6
Bottom Type	Sand
Investor Real Cost of Capital	10%
Real Oil Price (1974 Dollars)	10.00/BBL
Real Gas Price (1974 Dollars)	1.88/Mcf
No Ad Valorem Tax	--
No Allowables	--
No Gas Reinjection	--
Producing Wells Per Platform	20

*These values correspond to average characteristics typical of a pure gas drive reservoir.

**Associated-dissolved gas.

Water depths of 150 feet, 300 feet, and 450 feet were considered and platform design wave heights of 50 feet, 75 feet and 100 feet were examined. These combinations of depths and design waves cover the range from the Gulf of Mexico to the northern areas of the North Sea[1] and represent the usable limits of the present platform costing model.

Figures II-12, II-13 and II-14 display some of the major analytic results. These tables shown an estimate of the unit national cost of developing each of the hypothetical finds studied. Specifically, the numbers shown are the landed price of oil the developer would have to obtain in order to breakeven at a 10% return on the resource costs associated with the profit maximizing strategy given an assumed crude price of $10.00 per barrel. As such, these numbers are upper bounds[2] on the actual breakeven price since if the oil is priced well above the breakeven price it will generally pay the present value maximizing developer to increase his unit cost to bring the oil out faster. They are also upper bounds in the sense that they give no credit to the gas found and no credit to secondary oil recovered. The numbers shown in the tables do not include lease bids, royalties, or taxes which are not a cost to the nation but rather income transfers. The following patterns become evident in examining the results displayed in the tables.

- the dependence on distance to landfall is not particularly striking, expecially for smaller fields. While going from 25 miles offshore to 75 miles offshore increases unit cost about 10¢ per barrel, going from 75 miles offshore to 150 miles offshore results in little change in unit cost for all but the largest fields. The reason is that the model selects tanker

---

[1] Average assumed wave heights are generally 50 feet for Gulf of Mexico and Pacific Coastal areas; 65 feet for areas such as the Gulf of Alaska and Georges Bank; 100 feet for the northern areas of the North Sea.

[2] The concept of an "upper bound" as used here refers to the omission of both gas related costs and revenues so that the oil price alone must be sufficiently high to cover the attendant costs to achieve breakeven.

FIGURE II-12

ANALYSIS OF PRIMARY RECOVERY OFFSHORE

UNIT NATIONAL COSTS LANDED ($/ BARREL)

GAS DRIVE, NO RESTRICTIONS ON ALLOWABLES, DISTANCE TO LANDFALL = 25 Miles

CONDITION	ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS					
	2.0	1.0	.5	.2	.1	.05
Water Depth = 150'						
Design 50'	.67	.91	1.54	2.56	3.80	6.27
Wave 75'	.69	.93	1.57	2.61	3.87	6.41
Height 100'	.71	.96	1.43	2.68	3.95	6.58
Water Depth = 300'						
Design 50'	.77	1.02	1.51	2.83	4.15	X
Wave 75'	.89	1.17	1.72	2.95	4.65	X
Height 100'	1.15	1.34	2.13	3.47	5.65	X
Water Depth = 450'						
Design 50'	1.05	1.36	1.97	3.26	5.24	X
Wave 75'	1.55	2.05	2.89	4.86	8.34	X
Height 100'	2.44	3.32	5.14	8.54	X	X

Notes:

1. X implies field could not be profitably developed at $10.00 oil, $1.87 Gas, and 10% real cost of capital.
2. Underlining implies program chose to land oil by tanker.
3. Values correspond to ice-free conditions with no contingency for earthquake protection measures.

FIGURE II-13

ANALYSIS OF PRIMARY RECOVERY OFFSHORE
UNIT NATIONAL COSTS LANDED ($/ BARREL)

GAS DRIVE, NO RESTRICTIONS ON ALLOWABLES, DISTANCE TO LANDFALL = 75 Miles

CONDITIONS		ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS					
		2.0	1.0	.5	.2	.1	.05
Water Depth = 150'							
Design	50'	.74	1.02	1.54	2.49	3.80	X
Wave	75'	.75	1.04	1.57	2.53	3.87	X
Height	100'	.77	1.07	1.61	2.57	3.95	X
Water Depth = 300'							
Design	50'	.83	1.13	1.69	2.68	4.15	X
Wave	75'	.96	1.29	1.89	2.93	4.65	X
Height	100'	1.21	1.46	2.05	3.45	5.65	X
Water Depth - 450'							
Design	50'	1.12	1.35	1.92	3.24	5.24	X
Wave	75'	1.61	2.17	2.89	4.84	X	X
Height	100'	2.51	3.44	5.14	8.52	X	X

Notes:

1. X implies field could not be profitably developed at $10.00 oil, $1.87 gas, and 10% real cost of capital.
2. Underlining implies program chose to land oil by tanker.
3. Values correspond to ice-free conditions with no contingency for earthquake protection measures.

FIGURE II-14

ANALYSIS OF PRIMARY RECOVERY OFFSHORE

UNIT NATIONAL COSTS LANDED (\$/ BARREL)

GAS DRIVE, NO RESTRICTIONS ON ALLOWABLES, DISTANCE TO LANDFALL = 150 Miles

CONDITIONS		ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS					
		2.0	1.0	.5	.2	.1	.05
Water Depth = 150'							
Design	50'	.83	1.19	1.54	2.50	3.80	X
Wave	75'	.85	1.21	1.57	2.53	3.87	X
Height	100'	.87	1.24	1.61	2.57	3.95	X
Water Depth = 300'							
Design	50'	.93	1.30	1.69	2.68	4.15	X
Wave	75'	1.05	1.46	1.77	2.93	4.65	X
Height	100'	1.31	1.63	2.09	3.45	5.65	X
Water Depth = 450'							
Design	50'	1.22	1.64	1.96	3.24	5.25	X
Wave	75'	1.71	2.00	2.93	4.84	X	X
Height	100'	2.61	3.55	5.18	8.52	X	X

Notes:

1. X implies field could not be profitably developed at \$10.00 oil, \$1.87 gas, and 10% real cost of capital.
2. Underlining implies program chose to land oil by tanker.
3. Values correspond to ice-free conditions with no contingency for earthquate protection measures.

transport as more economical than pipeline as field size decreases and distance to shore increases. The hypothetical discoveries which the program lands by tanker are underlined in the tables. The difference between the cost of 75 miles of tanker transport and the cost of 150 miles is quite small due to the fact that the tankers are spending most of their time at either end of these extremely short routes.[1]

- In general, the influence upon unit costs of distance offshore, by itself, or design wave height, by itself, (or even water depth, by itself) is not too significant. It is only when these factors are considered in combination that striking differences in unit costs are observed for a given field size.[2] The difference between the most favorable combination of waterdepth and design wave height studied (150 feet and 50 feet, respectively) and the least favorable studied (450 feet and 100 feet, respectively) is about a factor of four in unit costs holding all other variables constant. Of the three locational variables studied, water depth appears to be the single most important.
- Certainly the most striking result of these evaluation runs is the implication that in terms of national cost, offshore oil can be quite inexpensive. When one compares the unit costs shown for at least the larger finds studied with the present cost to the nation of foreign crude ($8.00 to $11.00 per barrel) one comes quickly to the conclusion

---

[1] The costing routine is not sensitive to the added expense associated with crew and supply transport to the fields further offshore. This will usually not be significant.

[2] In general, these variables are not independent, but rather usually tend to simultaneously increase in magnitude together.

> that the loss in domestic market income associated with not developing a large offshore find on the OCS can easily approach $6-7 per barrel not landed.[1] Assuming foreign oil real costs to the nation of $10 per barrel (1974 constant dollars) through the future, for the largest hypothetical find we have studied (two billion barrels in place) this would imply a loss in present valued national income of from $2.2 - 2.6 billion depending on the design wave height and water depth.

However, according to the model, unit costs start increasing rather rapidly as one moves to smaller fields, for at least the less favorable combinations of water depth and wave height. At $10.00 per barrel oil and $1.87 per Mcf gas, a 50 million barrel-in-place find with our hypothetical reservoir characteristics can only be profitably developed at the lower end of the "water depth" and "distance offshore" range. A 100 million barrel-in-place find just about achieves breakeven at the higher end of this range. Recall that we are "crediting" the discovery for its primary production only. The possibilities for secondary and tertiary incremental recovery may push these lower limits on field size down by as much as a factor of two. Remember also that these are completely isolated discoveries in the sense that they are unable to take advantage of economies of scale such as those associated with sharing pipelines with neighboring fields.

It is also important to keep in mind that the model only considers conventional, space frame, steel platform technology. It does not consider concrete platforms nor subsea completions--both of which may be superior to conventional technology for certain unfavorable combinations of distance offshore, water depth, and design wave height.

---

[1] As long as the O.P.E.C. cartel is not broken, the resource cost of producing Persian Gulf crude and landing it in the United States is something less than $1.50.

These caveats not withstanding, it is clear from the results we do have that, if you find enough oil almost anywhere on the U.S. Lower 48 Continental Shelf, it will be, relatively speaking, "cheap oil."

(iii) Application of the Model: Results of Primary Recovery Analysis for Gulf of Alaska

The analysis of Gulf of Alaskan oil produces results not much different from that of the Lower 48 offshore. Figure II-15 displays the results of a series of runs meant to be representative of a hypothetical find in the Gulf of Alaska. The distance to landfall in the Puget Sound area has been set at 1500 miles. Oil and gas pipelines were disallowed for this exercise. The design wave height, 75 feet, is based on Tetratech studies of the 100 year wave in the area performed for the Council on Environmental Quality[8]. The cost of each platform has been arbitrarily increased by $4 million to cover increased mobilization and downtime expenses. Ice is not expected to be a problem offshore in the Gulf of Alaska. The results indicate that this Alsakan oil will be approximately 50¢ per barrel more expensive to land in the Lower 48 than a similar reservoir on the Lower 48 Continental Shelf. Not surprisingly, 50¢ per barrel is about the cost of transporting oil 1500 miles in small domestic flag tankers.[1] In summary, this oil, too, could be quite inexpensive depending on the size of the reservoir.

(iv) Impact of Allowables on Recovery Prospects: Lower 48 OCS and Offshore Alaska

Among the important assumptions underlying the results of the analyses presented above is the premise that there are no legal (as opposed to purely physical) restrictions on the rate at which the wells are produced. For the reservoir we have chosen

---

[1] The direct implication is that Gulf of Alaska production costs do not differ substantially from those estimated for Lower 48 OCS areas. The results of this analysis would not hold for areas in which there existed significant ice hazard.

FIGURE II-15

ANALYSIS OF PRIMARY RECOVERY IN GULF OF ALASKA

UNIT NATIONAL COSTS LANDED ($/BARREL)
GULF OF ALASKA, GAS DRIVE, NO ALLOWABLES DISTANCE TO LANDFALL = 1500 Miles
DESIGN WAVE HEIGHT = 75

CONDITIONS	ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS				
	2.0	1.0	.5	.2	.1
Waterdepth = 150	1.31	1.56	2.12	3.20	5.05
Waterdepth = 300	1.46	1.73	2.37	3.61	5.84
Waterdepth = 450	2.00	2.53	3.53	5.51	X

Notes:

1. X implies field could not be profitably developed at $10.00 oil, $1.87 gas, and 10% real cost of capital.
2. Values shown assume ice-free conditions and no contingency for earthquake protection measures.

to investigate, the wells are typically producing at rates of 3 to 4 thousand barrels per day. Such production rates and higher are quite common in the Middle East and North Sea. On the United States OCS, however, it is common practice to regulate reservoir and per well production, often limiting production rates to a few hundred barrels per well-day. The ostensible motivation for this regulation is that too rapid a withdrawal rate will decrease total recovery. This argument is an extremely tenuous one on three grounds:

- For most reservoirs, total recovery is a very weak function of rate of withdrawal, especially when secondary operations are taken into account.[1]
- From strictly an economic viewpoint, the objective function which will maximize real national wealth is not maximum recovery but maximum present valued recovery less present value of resource costs.
- In the absence of common pool problems, there is no reason to believe that the operators will produce in a manner so as to reduce present valued national income, for to do so would decrease the operator's present valued profits. In any event, the common pool problem is most easily and effectively met by the simple requirement that each reservoir must be operated in a unitized fashion.

The lie to the argument for reservoir production regulation is most clearly given by the manner in which it has been enforced in the past on the OCS. In general, the per well allowables have been set as a simple function of either the water depth or the well depth or both. These two variables by themselves in no way characterize a given reservoir response to a particular production schedule. In order to predict that response, we would at the very minimum, have to know the type of drive, the initial pressure, initial gas/oil ratio, oil and gas viscosity and permeability. Until the recent OCS Order 11, this information was not even available to the U.S.G.S. who set the allowables. It is fairly transparent that the policy of setting allowables is a historic holdover from land practice where at least the common pool argument held more force.

---

[1] For some reservoirs, ultimate recovery is measured by increasing withdrawal rates as we shall discuss later in Chapter IV.

However, since land practice at least in Louisiana was to base allowables on well depth, a pseudo-economic basis having nothing to do with reservoir response, one suspects that even in land regulation, this restriction functioned mainly as a form of proration in an attempt to maintain prices by constraining supply.

Prior allowables policies not withstanding, given the likelihood of allowables being set on future OCS discoveries, it is of interest to examine the effect of such regulation on the economics of our hypothetical find. The results shown in Figure II-16 represent a repeat of the earlier 75 mile offshore runs (Figure II-13) with one exception. The daily production rate of each well has been limited to 1000 barrels per day. The result, as can be seen by comparing Figure II-16 with Figure II-13 is to increase the unit national cost of landing these respective finds by about 20%. The corresponding decrease in national income can, as we see, be rather sizable. For our two billion barrel-in-place find this loss is about five hundred million dollars present value. This amount is roughly equivalent to the difference associated with considering this find in a water depth of 150 feet and wave height of 50 feet relative to considering the same find in a water depth of 450 feet with a design wave height of 100 feet. Primary recovery for this particular gas drive reservoir is completely insensitive to withdrawal rate and it pays the operator to produce this field quite rapidly if he is allowed to do so. Thus, the allowable's constraint is

FIGURE II-16

IMPACT OF ALLOWABLES ON RECOVERY PROSPECTS[1]

UNIT NATIONAL COSTS LANDED ($/BARREL)

GAS DRIVE, OIL ALLOWABLE: 1000 BARRELS PER DAY, GAS ALLOWABLE, 10 MMCFD,

DISTANCE TO LANDFALL = 75 Miles

CONDITION		ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS				
		2.0	1.0	.5	.2	.1
Water Depth = 150'						
Design	50'	.85	1.15	1.71	2.75	4.29
Wave	75'	.88	1.18	1.75	2.80	4.36
Height	100'	.90	1.21	1.80	2.87	4.45
Water Depth = 300'						
Design	50'	.97	1.28	1.91	3.03	4.67
Wave	75'	1.12	1.46	2.18	3.43	5.19
Height	100'	1.42	1.81	2.73	4.23	6.25
Water Depth = 450'						
Design	50'	1.31	1.67	2.52	3.90	5.81
Wave	75'	2.22	2.76	3.70	5.70	X
Height	100'	4.05	4.77	6.07	X	X

Notes:

1. X implies field could not be profitably developed at $10.00 oil, $1.87 gas, and 10% real cost of capital

quite expensive. For natural water drive reservoirs, the present value maximizing production rate may be considerably slower and the cost of enforcing allowables correspondingly less. We discuss this next.

(v) Impact of Water Versus Gas Drive on Recovery Prospects: Lower 48 OCS and Offshore Alaska

To establish costs for water drive fields versus gas drive fields, we have made a series of evaluation runs of the Offshore Development Program's water drive model. In these runs all the reservoir parameters were kept the same as in our earlier gas drive analysis with the exception that the reservoir was endowed with an active water drive.[1]

The response to this reservoir is qualitatively quite different from that of our earlier pure gas drive situation. Water is a much more efficient expulsion mechansim than gas but it typically operates at much slower rates. The result is much higher recoveries and much longer primary reservoir life. While the Offshore Development Model depletes the earlier gas drive reservoirs of primary oil in eight years or less, the larger water drive reservoirs are still producing, albeit at low rates, after 30 years. The resulting primary recovery is much higher, in the neighborhood of 65% as opposed to the earlier 17% for primary production of the same reservoir under pure gas drive. However, the percentage differences in present values are not as great as this due to the lower withdrawal rates under water drive. In general, our water drive reservoir represents, for its size, an extremely fortunate combination of characteristics. In the real world, only a small proportion of major U.S. reservoirs have primary production in excess of 50%.[2]

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[1] To be more precise, an infinite aquifer, Hurst-Van Everdingen edge drive.

[2] It should be pointed out, however, that with sufficient investment in water injection, production from the gas drive field can be made to look rather similar to that from water drive.

The water drive results for a moderately difficult combination of distance to landfall, design wave height, and water depth are compared with the corresponding gas drive results in Figure II-17. The unit national costs are roughly half that of the same gas drive field and the change in national income is about doubled. The 50 million barrel-in-place water drive field is comfortably "in the black" while the correspondingly sized gas drive field could not breakeven at a 10% required rate of return. The peak per well production rate of water drive reservoirs is roughly one-fourth that of their gas drive counterparts and in all cases was under 1000 barrels per day. Therefore, a 1000 barrel per day allowable would have no effect on production, and hence imply no loss in national income. However, an allowable in the neighborhood of a few hundred barrels, as is common in the Gulf of Mexico, would imply a loss.

In summary, all our earlier statements about the "relative cheapness" of large reservoir, OCS oil to O.P.E.C. oil certainly holds *a fortiori* for this very favorable set of reservoir characteristics. Moreover, we see that the imposition of inefficient MER and MPR restrictions can cut off supply from marginal fields, thereby "shifting the supply curve" upward and to the left.

(vi) Implications for Further Research

If one were willing to speculate about the size distribution of future offshore finds, numbers such as the ones developed in the above sections could be combined with such speculations to derive some implications about the shape, if not the overall dimensions, of the supply curve of yet-to-be-discovered offshore oil. Unfortunately, we know very little more about the distribution of the size of future offshore finds than we do about

FIGURE II-17

COMPARISON OF PURE GAS DRIVE AND WATER DRIVE RECOVERY AND PERFORMANCE ECONOMICS

DISTANCE TO LANDFALL = 75 MILES
WATER DEPTH = 300'
DESIGN WAVE HEIGHT = 75'
NO ALLOWABLES

	ORIGINAL OIL IN PLACE (10^9 BARRELS)					
	2.0	1.0	.5	.2	.1	.05
UNIT NATIONAL COST						
Gas Drive	.96	1.29	1.89	2.68	4.65	-
Water Drive	.48	.65	.91	1.65	2.49	3.16
A NATIONAL INCOME* (P.V. @ 10% REAL-BILLIONS OF 1974 DOLLARS)						
Gas Drive	2.7	1.3	.7	.23	.10	-
Water Drive	4.4	2.2	1.0	.55	.24	.11
PRIMARY OIL RECOVERY						
Gas Drive	17%	17%	17%	17%	17%	-
Water Drive	65%	68%	69%	70%	70%	62%
NUMBER OF PLATFORMS						
Gas Drive	9	5	3	1	1	-
Water Drive	9	5	4	2	1	1
TRANSPORTATION MODE						
Gas Drive	Pipe	Pipe	Tank	Tank	Tank	-
Water Drive	Pipe	Pipe	Pipe	Tank	Pipe	Tank
PRIMARY FIELD LIFE						
Gas Drive	8	6	5	4	3	-
Water Drive	40	40	27	19	16	10

* Assuming Cost to nation of alternative oil is $10/bbl,altervative gas $1.88/Mcf.

their overall magnitude. The distribution of the size of reported North Sea finds is quite different from that of the Gulf of Mexico finds. Inferences based on either sample lead to rather different conclusions which for yet-to-be-explored areas, may be equally wrong. Nonetheless, some interesting studies could be undertaken in this area, by assuming that, for example, the distribution of field sizes in the Gulf of Alaska will be similar to that off the Gulf Coast and then repeating the analyses using the North Sea distribution to derive the comparative sensitivity between the two distribtuional assumptions.

We have not undertaken such work here. However, even without these analyses, it is possible to note that most of the oil which has been landed from offshore fields, including the Gulf, has been produced from fields with 500 or more million barrels-in-place (see Chapter III). Under present technology such oil would be quite competitive with present O.P.E.C. prices regardless of where on the U.S. Continental Shelf it were discovered.

Potential Discoveries: Onshore Alaska

The Prudhoe Bay Find: Recovery Prospects

Given the importance of Alaska to the nation's oil supply curve, it is perhaps worthwhile to spend some time reviewing recent developments in the Alaskan situation.

At present these developments can be summed up in two words: Prudhoe Bay. There are three pools at Prudhoe Bay. The shallowest is the Kuparuk River pool, whose depth is variously listed at 5500' to 7000'. The deepest is the Lisburne pool at 10,550'. However, at present, developers are concentrating almost entirely on the Prudhoe (Sadlerochit) Pool. The present publicized estimates of the size of this reservoir is 24 billion barrels of oil in place with about 30 trillion cubic feet of gas. This reservoir is four times as large as the largest previously discovered domestic field (East Texas). The current estimate of recoverable reserves of 9.6 billion barrels represents over 25% of all the domestic oil which the A.P.I. presently lists in its recoverable category. When this reservoir reaches its full development of about two million barrels of oil production per day, it will be supplying about one eighth of the country's oil consumption.

Given this importance, available information on this reservoir is surprisingly scarce. Figure II-18 lists our best estimates of the field's major characteristics pieced together from a variety of sources. These estimates vary greatly in quality. The original oil-in-place, gas-in-place, oil gravity and oil sulphur content are widely quoted figures that may be regarded as reasonably accurate. The area, thickness, and porosity are Martingale estimates[1] based on (a) qualitative statements in the industry press; (b) the fact that the operators, ARCO and BP, are developing the field with about 150 wells on a 640 acre spacing; and (c) some rough volumetric calculations. These numbers are probably correct within "a tolerance" of plus or minus 30%. The pressure and temperature estimates are based on (a) qualitative reports; (b) the depth of the reservoir; and (c) the reported design specifications of surface separation and reinjection equipment. The biggest uncertainty is undoubtedly permeability which is rumored to be "good." Other than some piecemeal well test figures, however, we have no hard data. Our best estimate is that average absolute permeabilities are in the neighborhood of 150 mds, though they easily could be twice as high. Our estimate of the oil viscosity is based on the oil gravity and an estimate of the solution gas/oil ratio at reservoir conditions. We have no data on connate water saturation or water influx but judging from the apparent lack of water separation facilities very little water influx is expected. All in all, these characteristics imply excellent reservoir conditions by gas drive standards.

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[1] See footnote to Figure II-18 for more recent estimates for these parameters.

FIGURE II-18

ALASKA ONSHORE ANALYSIS: PRUDHOE POOL

CURRENT ESTIMATES OF MAJOR RESERVOIR CHARACTERISTICS*

Original Oil in Place	24 billion barrels
Original Gas in Place	30 trillion SCF
Depth	8700 feet
Area	96,000 acres
Average thickness (oil)	150 feet
Porosity	22%
Oil API Gravity	27°
Sulphur Content	.82%
Gas Specific Gravity	.6
Initial Pressure	4000 psi
Reservoir Temperature	180°F
Rock Type	Clean, consolidated Sandstone
Drive	Large gas cap, No water
Permeability	100-200 millidarcies
Oil Viscosity	1 cp

*More recent estimates indicate that average thickness may be closer to 167' than to 150'; porosity in the range of 25-30% rather than 22%; permeability in the range 250-300 md rather than 100-200 md; and that the average production rate is close to 8000 BBL per day per well.

In order to obtain some independent insight on this field, we have applied a modified version of the Martingale Offshore Development Model to a reservoir with the above characteristics. In these runs, the platform building and transport routines were decoupled from the gas drive reservoir model. In the first such run, we attempted to simulate the purely primary production from this reservoir, and thus no gas reinjection was specified. Permeability was set at 200 mds. The resultant oil recovery was 28% of the original oil in place. The program produced oil withdrawal rates somewhat greater than reported industry planned rates with 200 wells used and peak production at 2.5 million barrels per day. Reportedly the operators plan to use about 150 wells with a peak production of 1.6 - 1.8 million barrels per day. Both the model and the industry plans involve per well production rates in the neighborhood of 10,000 bpd. Using the program's development strategy with no gas reinjection, the period of peak production was six years after which the field went into rapid decline and was completely depleted of primary oil in 10 years.

In a second run of the model, nearly all the produced gas was reinjected, as is ARCO and BP's stated intention. In this run, total oil recovery was 35% or 8.4 billion barrels of oil. This is slightly less than the present API recoverables estimate of 9.6 billion barrels which undoubtedly contains some provision for natural gas liquids. Under this plan, peak production once again was about 2.5 million barrels per day which lasted for seven years. The field was no longer producing oil after 13 years.

Several additional runs were made varying absolute permeability. Halving the permeability to 100 millidarcies had no effect on ultimate recovery but reduced the period of peak production to three years while reducing the decline rate and extending overall field life to 18 years. Halving permeability again to 50 millidarcies dropped ultimate recovery to 34% and completely changed production rates, resulting in a field life of 40 years despite intensive gas reinjection. Such a production profile is clearly uneconomical from a present value perspective and would call for closer well spacing. These results, then, lend further credance to our guess that the reservoir's permeability is in the 100 to 200 md range or greater.

With respect to our earlier discussion of allowables, it is interesting to examine what would happen to Prudhoe Bay if the kind of production rate limits common in the Gulf were also placed on this field. We reran the program with the same reservoir characteristics (200 mds), a per well allowable of 2000 bpd (still much higher than the Lower 48), and the same number of wells. The result was a drop in the present valued economic worth of the field of 70%, representing a very large loss in present valued national income. Of course, in reality the developers would likely respond to these allowable rates by using roughly five times as many wells at an enormous income loss to the nation of perhaps two billion dollars. Prudhoe Bay, then, represents a classic example of a field for which even rather high production rate limits (by Lower 48 standards) would be extremely costly in terms of national income. One wonders what would have happened if this field had been found in the Gulf of Mexico.

With respect to the prospects for secondary recovery at Prudhoe Bay, it appears to be fairly safe to say that current estimates of the recoverable reserves from this field are based solely on gas reinjection. Unless some of the remaining 15 billion barrels of oil in the Prudhoe Bay can be recovered, Prudhoe Bay will have a productive life of little more than 15 years.

Costing North Slope Oil

The Alaskan North Slope is sufficiently unique such that the development and programming of formal costing routines for these reservoirs was deemed not warranted for the purposes of this preliminary effort. However, even without such costing capability, we can be quite sure that the unit wellhead cost of primary Prudhoe Bay oil recovery will be very small. The cost of a North Slope production well have been variously estimated at between $2-4 million including gravel pad, gathering network and local infrastructure.[9] This aggregates to between $300 and 600 million for the entire field. Conservatively assuming 9.6 billion barrels recoverable in total, a production rate of only 1.2 million barrels per day, and a three year delay between time of investment and start of production, the wellhead price per barrel required to provide the investor a real rate of return of 10% is about 13¢ at $2 million investment per well, and approximately 26¢ at $4 million investment per well. Even making a "generous allowance" for operating expenses, research and development outlays and similar expenditures, we can be sure that the wellhead cost of Prudhoe Pool oil (exclusive of lease and royalty payments) is well below 50¢ per barrel.

In order to transport this oil to the sourthern coast of Alsaka, the operators are building a 790 mile, 48" diameter pipeline. Approximately 400 miles of this pipeline will be supported above ground and insulated to prevent melting the permafrost. This pipeline will use a low carbon steel averaging about 1/2" in wall thickness, rated at approximately 65,000 psi yield. Throughput of 1.2 million barrels per day will require 8 gas turbine pumping stations each rated at about 40,000hp. The northernmost four stations will use Prudhoe Bay gas supplied by a separate 8-10" gas line. The other stations will obtain their fuel from the crude via simple topping plants. Throughput can be increased to two million barrels per day by the addition of four more pumping stations and some additional pumping power. The pipeline is presently scheduled for completion in Fall, 1977. The terminus of the pipeline will be at Valdez where four fixed pier tanker berths, about 7 million barrels of crude tankage and 1.5 million barrels of ballast water tankage will be provided. On-site pipeline and terminal employment will peak at about 6200 people in 1976.

Here again, this pipeline is such a unique project that an attempt at synthesizing and programming a costing routine was not deemed appropriate. Various industry sources estimate the total projected cost of the pipeline and terminal to be between $4.5-6.0 billion.[10,11] Two years ago, the projected cost was placed at $2.5 billion.[12] In 1969, the Prudhoe Bay developers estimated the cost of this project at $900 million.

The uniqueness of this project notwithstanding, we cannot reconcile the expenditure of these huge sums with our understanding of the major elements of cost. Figure II-19 indicates our very rough(but what we believe to be "generous")estimates of some of the major cost items. While this "back-of-the-envelope" costing is incomplete, it does contain the major expenditure categories. Thus, if we had to hazard a guess at what the pipeline should cost, we would have to say between $2.5-3.0 billion. Perhaps it is possible that, in their haste, the builders have allowed project costs to get out of control.

In any event Figure II-20 shows the required per barrel tariff to provide investors in the pipeline and terminal 10% and 15% real returns, respectively. The values are shown as a function of the initial cost of the project assuming 1.2 million barrels per day throughput and an investment outlay made three years prior to the commencement of operations.

Making a heavy allowance for operating expenses, at 10% real cost of capital, we place the costs shomwhere between $1.25 and $2.50 per barrel (before Alaskan and U.S. taxes and royalties) to transport the oil across Alaska and load it on tankers.

As we have already seen, the cost of transporting this oil via U.S. flag tanker to the West Coast will be in the neighborhood of 50¢ per barrel. In short, assuming a 10% real cost of capital, the total cost to the nation of producing

FIGURE II-19

AUTHORS' ESTIMATES OF ALYESKA PROJECT COSTS

MAJOR COST ITEM	EST. COST	BASIS FOR ESTIMATE
Pipeline steel	$\$250 \times 10^6$	Based on 500,000 tons at \$500 per ton. Bulk of pipline steel ordered in Japan in 1969 when price of mill steel was \$200 per ton. Add 40% for inventory cost to 74.
Vertical supports & heat pipes (mat.)	100×10^6	Contract quotes, 1974. Extremely expensive on a per ton basis.
Haul road	200×10^6	Industry quote, 1974. Haul road was built in 154 days with free gravel and right of way.
Pumps, 324,000 hp.	200×10^6	Based on \$600/hp, double Lower 48. Contract quote Cooper Bessemer for gas turbines at $\$31 \times 10^6$.
On-line storage	40×10^6	1.5 million bbls. at \$25/bbl. Six times Lower 48.
Station bldgs.	120×10^6	600,000 ft at $\$200/\text{ft}^2$. Ten times Lower 48.
Excavation (stations)	40×10^6	4,000,000 cu yds at \$10/cu yd.
Gas Line	50×10^6	Cold gas line, needs no special permafrost treatment. Will be laid along haul road. 140 miles, 8 to 10 inch. at \$350,000 per mile. Twice Lower 48.
Labor (in Alaska)	$1,000 \times 10^6$	20,000 man-years at \$50,000 per year average.
Crude tankage (Val.)	200×10^6	7 million barrels at \$30/bbl. Six times Lower 48.
Ballast tankage	50×10^6	1.5 million barrels at \$30/bbl.
Excavation (Val.)	50×10^6	5 million cu yds at \$10/yd.
Fixed Berths	300×10^6	4 at $\$75 \times 10^6$ each. Two/three times Lower 48. Kievit/Willamette was awarded contract of $\$130 \times 10^6$ for four berths - may not include piplines.
Insulation Costs	70×10^6	1975 contract quote by Owens-Corning (instal.includ.)
TOTAL*	$\$2,670 \times 10^6$	

*Does not include construction equipment, temporary housing and topping plant equipment. Otherwise this figure should represent an extremely generous allowance since labor is doublecounted in much of the above.

FIGURE II-20

ESTIMATES OF REQUIRED ALYESKA TARIFF*

(exclusive of taxes and royalties)

INITIAL INVESTMENT	COST OF CAPITAL (real)	
	10%	15%
$3.0 x 10^9	$1.08/bbl	$1.77/bbl
4.5 x 10^9	1.62	2.15
6.0 x 10^9	2.16	3.54

*See text for throughput and investment staging assumptions.

primary Prudhoe Bay crude and delivering this oil to the West Coast is probably about $2.50 per barrel, and certainly less than $4.50 per barrel.[1] Once again this is "cheap oil" when compared to imported crude at present O.P.E.C. prices. Having invested in the pipeline and the technology and a certain amount of infrastructure (e.g. haul roads) if additional primary oil is found on the North Slope in large fields, the incremental unit cost in constant dollar terms, of delivering this new oil to the Lower 48 will certainly be less than the costs quoted above.

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[1] It is important to remember that the industry was lobbying hard for the pipeline when the market value of this crude on the West Coast would have been $3.50 per barrel or less. So we can be confident that these estimates are reasonably generous.

III. ENHANCED RECOVERY PROSPECTS: COMPILATION AND CLASSIFICATION OF MAJOR FIELD DATA

Introduction and Overview

An obvious preprequisite to the assessment of enhanced recovery prospects for already discovered oil is knowledge of the characteristics of the reservoirs within which this oil is contained. Thus, a comprehensive review of the available sources of information and the actual compilation of those data we could obtain constituted a very major portion of this effort. In this chapter, then, we will discuss those data identification, collection and classification activities which preceded the actual assessment of specific secondary and tertiary methods. Listed by chronology of occurence, these important activities consisted of:

- comprehensive literature review and identification of alternative information sources;
- actual data collection and compilation of the "Big Fields" data file containing selected physical characteristics of approximately 350 major domestic oil fields;
- development and application of utility programs to perform special operations on selected entries in the Big Fields file.[1]

We shall now discuss each of these tasks individually in the remaining section of this chapter.

Literature Review and Survey of Available Data

In order to obtain a balanced perspective as to the availability and quality of technical information and data which might be pertinent to our study, numerous possible sources were consulted. These included (in arbitrary order):

(1) U.S. Bureau of Mines
(2) U.S. Geological Survey
(3) U.S. Federal Power Commission

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[1] The nature of these operations and their importance with regard to the assessment of enhanced recovery potential will be described in detail later in this chapter.

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(4) Texas Railroad Commission

(5) Louisiania State Department of Conservation, Oil and Gas Division

(6) California State Department of Conservation, Oil and Gas Division

(7) Interstate Oil Compact Commission

(8) International Oil Scouts Association

(9) Oil Law Records Corporation

(10) Oklahoma University

(11) American Petroleum Institute

(12) Petroleum Information Corporation

(13) The Oil and Gas Journal

(14) Texas State House Reporter

(15) AMOCO Production Company

(16) Standard Oil Company of California

(17) Tenneco Oil Company

(18) Getty Oil Company

Each of the above organizations was contacted by telephone and/or personal visit. In some cases, as with the Texas Railroad Commission, several days were spent on-site interviewing knowledgable contacts as well as transcribing data from hearings transcripts, MER applications, etc. Three California operators of thermal projects (Getty, Standard and Tenneco) permitted us to visit selected recovery operations sites and provided much useful information and documentation concerning their respective activities in these fields.

Appendix A contains a brief profile outlining each of these contacts. The major points of each contact are summarized and the names, mailing addresses and telephone numbers of key individuals with whom we spoke provided where available..

In addition the reader should scan the numerous Bibliography entries as well as the footnotes which appear in each section for references to the general research and periodical literature.

Most importantly, however, this thorough review led us to the conclusion that, for the less than 500 of the largest U.S. fields which constitute approximately 75% of domestic production, the data necessary for our study were available in one form or another. The next section describes the results of our attempt to assemble these data, reconcile discrepancies among alternative sources and estimate missing pieces.

Compilation of the "Big Fields" Data File

The Big Fields data file contains information on selected characteristics of 349 major domestic oil fields. Included in the file are estimates of field discovery date, average depth, acreage, thickness, type of trap, type of rock, primary drive mechanism, secondary drive mechanism, tertiary drive mechanism, oil API gravity, sulphur content, absolute permeability, porosity, percentage connate water, three estimates of current oil saturation, two estimates of original oil-in-place, Oil and Gas Journal estimates of recoverable reserves, cumulative production through end-of-year 1972, and our best estimate of remaining oil-in-place.

Figure III-1 lists the variable descriptions corresponding to the numbered column headings in Figure III-3 which is a computer print-out of the data file, itself. Figure III-2 contains descriptions of the abreviated codes which appear in certain columns of Figure III-3 and indexes these codes to their respective variables.

Zeros or blanks in the data tables imply the corresponding piece of data could not be obtained or estimated.

The file was compiled from a variety of sources. The basic field list is the Oil & Gas Journal (OGJ) listing of all U.S. fields rated by OGJ at over 100 million barrels of ultimate recovery.[28] This list[1] has been concatinated both with Halbouty's listing of major oil fields[29] as well as with data on about 20 fields which we extracted from the literature because they too appeared likely to have an OOIP volume

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[1] Another very useful source was an OGJ article entitled "Journal Survey Shows Recovery Projects Up"; March 25, 1974. Figures III-4 and III-5 include data tables reproduced from a reprint of that article.

FIGURE III-1

VARIABLE DICTIONARY: BIG FIELDS DATA FILE

Variable Contained Under Column Heading	DESCRIPTION (Units)
1	Five character alphanumeric code; 1st 2 characters designate state (district) and next 3 characters represent arbitrary sequence no. for field within that state
2	Field name
3	Quoted or estimated field discovery date
4	Average depth (ft.)
5	Average thickness to pay (ft.)
6	Field area (est. acres)
7	Type of trap (see codes Figure III-2)
8	Type of rock (see codes Figure III-2)
9	Primary drive mechanism (see codes Figure III-2)
10	Secondary drive mechanism (see codes Figure III-2)
11	Tertiary drive mechanism (see codes Figure III-2)
12	Oil gravity (°API)
13	Sulfur content (% x 100)
14	Absolute permeability (millidarcies) (See codes Fig. III-2)
15	Porosity (%) (See codes Figure III-2)
16	Connate water (%)
17	OGJ estimates of ultimate recovery (MMBBLS)
18	Cumulative production through end-of-year 1972 (MMBBLS)
19	Quoted original oil-in-place (MMBBLS)
20	Estimate I - original oil-in-place[1] (MMBBLS)
21	Estimate I - current oil saturation[1] (%)
22	Estimate II - current oil saturation (%)
23	Estimate III - current oil saturation (%)
24	Estimate II - original oil-in-place[1] (MMBBLS)
25	Estimated remaining recoverable oil-in-place[1] (MMBBLS)

[1] See text for explanation of estimating procedure.

FIGURE III-2

DEFINITION OF CODES AND SYMBOLS - BIG FIELDS DATA FILE

VARIABLE	CODE EXPLANATION
Type of trap (7)	A - anticline F - fault Z - salt dome S - stratigraphic
Type of rock (8)	SS - sandstone LM - limestone DO - dolomite
Primary drive mechanism (9)	G - gas drive W - natural water drive
Secondary drive mechanism (10)	G - gas injection W - waterflood
Tertiary drive mechanism (11)	2 - CO_2 H - hydrocarbon S - steam M - micellar C - combustion
Permeability (14)	P - poor M - moderate EX - excellent
Porosity (15)	F - fair PR - porous
Cumulative production (18)	S - cumulative production not available by formation but only for entire field

FIGURE III-3

BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

```
  1         2               3      4     5      6  7  8  9 10 11 12  13    14 15 16     17    18    19    20 21 22 23   24    25

AL001 GRANITEPOINT        1965      0     0   3000 A     G        0                0     86    47   900   338  0  0  0    0   653
AL003 MIDGROUNDSHOALS     1963      0     0   6000 A     G        0                0    116    68   589   467  0  0  0    0   521
AL002 MCARTHURRIVER       1965   9572     0   6000 A     G       36                0    175    69  1000   620  0  0  0    0   931
AL004 SWANSONRIVER        1957  11150     0   6200 A     G       37                0     72   135   437   526  0  0  0    0   302
AL005 TRADINGBAY             0      0     0      0 A     G        0                0     23   405     0  1037  0  0  0    0   682
AL006 PRUDHOEBAY/CRET     1968   6765     0      0 A  SS G        0                0   9599     4 24000 24392  0  0  0    0 23976
AL007 PRUDHOEBAY/SADL     1968   8100     0      0 A  SS G        0             25 0     51     0     0     0  0  0  0    0     0
AL008 PRUDHOEBAY/LISB     1968   8700     0      0 A  LN G        0                0     52     0     0     0  0  0  0    0     0
AL009 UMIAT                  0      0     0      0       G        0                0            0     0     0  0  0  0    0     0
AB001 CITRONELLE          1955  10900    15  16400 A     G       40       100   12 0     49   101   416   535  0138  0    0   315
AP001 BRADFORD            1880   1500    24  80000 AP SS G B     45  11   800   20 0     15   654     0  3345  0 90  0    0  2691
AP002 ALLEGHENY           1880   1500     0  30000       G        0  11            0      2   166     0   840  0  0  0    0   674
AR001 MAGNOLIA            1938   5450    93   4400 A     G W     38  97 10850   17 0      8   152   494   444  0 61  0    0   342
AR002 SMACKOVER           1922   2200    10  22000 A  SS G    C  20 210 10000   25 0     27   503  1513  1537  0237  0    0  1010
AR003 SCHULEREAST         1937   5580     0   7900 A     G       42  36            0      6   105   362   322  0  0  0    0   257
AR004 ELDORADO            1920      0     0   1300 A     G        0                0            0   204     0  0  0  0    0     0
CL001 BEVERLYHILLS           0   2840     1    500       G G C   20       100   20 0     42    70     0   452  0299  0    0   312
CL002 BREAOLINDA          1884   3500    50   2600 AF SS G       20 100  5000   29 0     31   337     0  1487  0393  0    0  1150
CL003 COYOTEEAST          1911   3318     0   1500 AF    G       23 130         PR 0      6    97     0   416  0  0  0    0   319
CL004 COYOTEWEST          1909   3500     0   1100 AF    G B     25  82  4730   PR 0     23   228     0  1014  0  0  0    0   786
CL005 DOMINGUEZ           1923   3800   200   1700 AF    G       34 110         25 0     13   256     0  1087  0126  0    0   831
CL006 HUNTINGTONBEACH     1920   2100   250   6500 A  SS G       18 160 20000   27 0    129   884  6018  4093  0151  0    0  5134
CL007 INGLEWOOD           1924   2200     0   1200 AF    G W     23 250         30 0     27   290  1891  1281  0  0  0    0  1601
CL008 LONGBEACH           1921   4400     0   1800 AF    G       27 130         30 0     24   873  3250  3624  0  0  0    0  2377
CL009 MONTEBELLO          1917   3500     0   1400 AF    G       25             PR 0      4   133     0   755  0  0  0    0   572
CL010 RICHFIELD           1919   3800     0   1600 A     G W     20             PR 0     21   162     0   759  0  0  0    0   577
CL011 SANTAFESPRINGS      1919   2117     0   1500 AF    G       11 225         PR 0     13   599     0  2472  0  0  0    0  1073
CL012 SEALBEACH           1926   8600     0    900 AF    G       25             PR 0      9   185   743   734  0  0  0    0   558
CL013 TORRANCE            1922   4400     0   6700 AF    G W     20             27 0     13   177   910   763  0  0  0    0   733
CL014 WILMINGTON-RANG     1932   2750     0  13500 AF SS G B SP  19 100 20000   33 23   830  1550  9355  9615  0  0  0    0  7305
CL015 YORBALINDA          1937   1000   325    200       G    S  15        6000   30 0           27   100     0  0 48  0    0    73
LN001 CADDO-PINEISLND     1903    767    10  96100 A     G W     20  27     M   PR 0     33   307     0  1333  0 55  0    0  1026
LN002 DELHI               1944   3000    20  44100 M     G       44   8     M   PR 0     57   153     0   823  0 39  0    0   670
LN003 HAYNESVILLE         1921   2700    20  17400       G B     35         M      0     17   168     0   725  0  0  0    0   557
LN004 RODESSA             1935   5300    15  19600 A     G       40         M   PR 0      5   175     0   706  0 93  0    0   531
LN006 BLACKLAKE           1964      0     0   1600 R     G        0                0            0     0     0  0  0  0    0     0
LN007 COTTONVALLEY        1922      0     0   1400 A     G        0                0            0     0     0  0  0  0    0     0
LN008 LAKESTJOHN          1942      0     0   1300 D     G        0                0            0     0     0  0  0  0    0     0
CC001 CARPINTERIAOFF         0      0     0      0       G        0                0     43    38     0   361  0  0  0    0   323
CC002 CATCANYONWEST       1908   3000   450   2700 A  SS G       12      12000   30 0     17   134     0   673  0 19  0    0   539

  1         2               3      4     5      6  7  8  9 10 11 12  13    14 15 16     17    18    19    20 21 22 23   24    25
```

FIGURE III-3 (continued)

BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

```
  1         2                3      4    5       6  7   8  9 10 11  12  13     14 15 16     17    18    19    20 21  22 23   24     25

CC003 DOSQUADROS          1969   3673    0       0         G         0                0    105    71   796   795  0   0  0    0    725
CC004 ELWOOD              1928   5620    0     700 A       G        35                0      1   103   226   464  0   0  0    0    123
CC005 ORCUTT              1902   3578  350    3900 DF      G  W     22 300      M  F  0     17   145     0   723  0  36  0    0    578
CC006 RINCON              1927   2700  400    1900 A       G        26 170     EX 20  0     16   116   392   589  0  23  0    0    276
CC007 SANARDO             1947   2300  115    4200 A   SS  G     S  12      77500 35  0     79   249  1473  1463  0  93  0    0   1224
CC008 SANTAYNEZ           1934  10000    0       0         G        36                0           0     0     0  0   0  0    0      0
CC009 SANTAMARIAVALLY     1934   4753  500    5600 M       G        12 520     EX  F  0      9   152   900   719  0  23  0    0    718
CC010 SOUTHMOUNTAIN       1915   4400  550    3300 A       G        20        700 23  0     20   127     0   656  0   9  0    0    529
CC011 VENTURA             1916   3400  500    3400 AF  SS  G  W  M  30  33   2500 17  0     81   771     0  3800 0135  0    0   3029
IL001 CLAYCITY            1937   2100   15   91000 A       G  W     35  19        PR  0     23   302  1832   923  0  58  0    0   1530
IL002 DALE                1940      0    0   18900 A       G         0                0      5   100   962   293  0   0  0    0    862
IL003 LOUDON              1938   1000   10   24000 A       G  W     36  20            0     27   358   600  1093  0   0  0    0    242
IL004 NEWHARMONY          1939   1000   10   30000 A       G  W     34                0     18   152   935   493  0   0  0    0    783
IL005 SALEM               1938   1800   15   14900 A       G  W     37  16   3000     0     20   350   500  1051  0   0  0    0    150
IL006 ROBINSON            1909    580   30    3900         G  W  M  30                0           0     0     0  0   0  0    0      0
IL007 OLDILLINOIS         1905      0    0  130000 A       G         0                0           0     0     0  0   0  0    0      0
KY001 BIGSINKING          1917   1000    0   14100 M   SS  G  W  P  38        400 22  0           0     0     0  0   0  0    0      0
KA001 BEMIS-SHUTTS        1928   3403   20   13200 D       G        34  57            0     21   214     0   714  0   0  0    0    500
KA002 CHASE-SILICA        1931   3300   20   53400 A       G  W     40  35            0     12   248     0   793  0   0  0    0    542
KA003 ELDORADO            1915    650   15   26500 A   SS  G  W  M  34  26    500 27  0     12   278     0   882  0  72  0    0    604
KA004 HALL-GURNEY         1931   2300   15   29300 A       G        39  50            0     17   123     0   426  0   0  0    0    303
KA005 KRAFT-PRUSA         1937   2900   25   21300 A       G        37                0      9   116     0   383  0   0  0    0    264
KA006 TRAPP               1936   2330    5   36300 A       G        39  41            0     15   204     0   666  0   0  0    0    462
CO001 RANGELEY            1933   6200  275   28000 A       G  B     34  50      M 14  0    128   472  1993  1908  0  18  0    0   1508
CF001 WILSONCREEK         1938   6572    0    2100         M  B     49  10     EX 17  0           0   200     0  0   0  0    0      0
FL001 JAY                 1970  15500  160       0         G  W     50                0    236    14   700  1000  0   0  0    0    696
CS001 BELRIDGESOUTH       1911   1042   30    9200 A   SS  G     S  15 160  30000 34  0     82   178     0  1045  0   0  0    0    867
CS002 BUENAVISTA          1909   3156  100   16300 A       G        20  59        25  0     41   609     0  2613  0  63  0    0   2004
CS003 COALINGA            1887   1899    0   19300 A   SS  G        19  75  10000 28  0     59   619     0  2726  0   0  0    0   2107
CS004 COALINGANOSE        1938   6455    0    4000 N       G        37  25            0     38   425  1900  1861  0   0  0    0   1475
CS005 COLESLEVEENORTH     1939   9500  250    3800 A   SS  G  B  M  32  80    950 21  0     15   139   449   619  0  20  0    0    310
CS006 CUYAMASOUTH         1949   2128   30       0         G  B     30  42        23  0     12   206     0   876  0   0  0    0    670
CS007 CYMRIC              1916   4000  150    3300 MF  SS  G  G     16  15  40000 32  0     31   125     0   627  0  41  0    0    502
CS008 EDISON              1934   1000   75    6600 M       G        19  80  20000 30  0     10   111   331   486  0  19  0    0    220
CS009 ELKHILLS            1919   2300    0   19600 AF      G  B     25  90        PR  0   1020   282     0  5234  0   0  0    0   4952
CS010 FRUITVALE           1928   4218  155    3300 M       G        20  90        PR  0      7   100     0   430  0  33  0    0    330
CS011 GREELY              1936  10000  150    2100 AF  SS  G  B  M  35  80    180 21  0      4   107   293   446  0  36  0    0    186
CS012 KERNFRONT           1915   2350   70    4500 MF  SS  G        14  90  15000 32  0     43   129   903   691  0  99  0    0    774
CS013 KERNRIVER           1899    913  130    8700 M   SS  G        13 110  30000 35  0    397   577 [illegible] 3915 0109  0    0   3338
CS014 KETTLEMANNDOME      1928  10000  400   13700 A       G  G     35  80        19  0      5   451  2040  1833  0  20  0    0   1589


  1         2                3      4    5       6  7   8  9 10 11  12  13     14 15 16     17    18    19    20 21  22 23   24     25
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FIGURE III-3 (continued)

BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

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  1          2             3      4     5       6  7  8  9 10 11 12  13    14  15 16      17    18    19    20  21 22  23   24   25

CS015 LOSTHILLS          1910   6000  700    3900 A  SS G W C  16       59000 37  0      21   115     0   547  0  6   0    0   432
CS016 MCKITTRICKMAIN     1887   9144  600    1500 MF SS G   S  15 100  20000 36  0      48   150     0   796  0 26   0    0   646
CS017 MIDWAYSUNSET       1894   2810  100   24900 A  SS G   C  19 100  20000 33  0     348  1158     0  6054  0 77   0    0  4896
CS018 MTPOSO             1923   1800  500    3500 MF SS G   S  15  80  50000 33  0      13   164   435   712  0  6   0    0   271
CS019 RIOBRAVO           1937   6000  250    2000 AF    G B    35              22  0       4   113   387   470  0 32   0    0   274
MI001 BAXTERVILLE        1944   8000   57   16000 D     W      15 270  10000 25  0      83   152     0   644  0 28   0    0   492
MI002 HEIDLEBERG         1944   7000   40    9900 Z     W      22       10000 29  0      45   104     0   403  0 34   0    0   304
MI003 TINSLEY            1939   4500   20   12400 A     W      34 102   4710 24  0      30   190     0   603  0 89   0    0   413
MI004 LITTLECREEK        1958  10350    0       0    SS G W 2  39         900 23  0            47   102     0  0  0   0    0    55
MO001 BELLCREEK          1967   4500   27   15000 S  SS G      30         100     0      59    51 (619)  407  0  0   0    0   568
MO002 CUTBANK            1926   2700   15   72600 M     G      37  90   5000     0      36   141     0   779  0  0   0    0   648
LO001 BAYMARCHAND2       1949   8000  150   24100 Z  SS W      28  46   5000 27  0     286   364     0  1344  0 13   0    0  1020
LO002 EUGENEIS126        1950   8000  150    3000 Z     W      38              PR  0      45    80     0 [illegible] 0 21   0    0   146
LO003 EUGENEIS175        1956  11700   79       0       G      34           EX PR  0      91    19     0 [illegible] 0  0   0    0   215
LO004 EUGENEIS276           0      0    0       0       G       0                  0     129    36     0   351  0  0   0    0   315
LO005 GRANDEISLE16       1948   8000  150    8100 Z     G B    35  25   5300 29  0     171   179     0   745  0 21   0    0   566
LO006 GRANDEISLE43       1956   8000   70    1100       W      30       4000 25  0     248   122     0   709  0446   0    0   666
LO007 GRANDEISLE47       1955   8000  100    3600 A     W      34   2   4000 25  0      44    56     0   213  0 22   0    0   157
LO008 MAINPASS35         1951   7500   75    4700 NF    W      27  17      M PR  0      25    75     0   213  0 20   0    0   138
LO009 MAINPASS41         1957   6000   60       0       W      30  21     EX PR  0     161   119     0   596  0  0   0    0   477
LO010 MAINPASS69         1948   6000   40   14800 A     W      30  16     EX PR  0      88   172     0   554  0 33   0    0   382
LO011 MAINPASS306           0      0    0       0       G       0                  0     130    20     0   319  0  0   0    0   299
LO012 SHIPSHOAL204          0      0    0       0       G       0                  0      89    16     0   224  0  0   0    0   203
LO013 SHIPSHOAL207          0      0    0       0       G       0                  0     144    31     0   373  0  0   0    0   342
LO014 SHIPSHOAL208       1962  10000    0       0       G       0                  0     154    71     0   479  0  0   0    0   408
LO015 SOUTHMARSHIS73        0      0    0       0       G       0                  0      75    30     0   224  0  0   0    0   194
LO016 SOUTHPASS24        1950   6520   99       0 A     G      27  26              0     150   340     0  1044  0  0   0    0   734
LO017 SOUTHPASS27        1954   7000   40       0 Z     G      34  37              0     151   234     0   870  0  0   0    0   536
LO018 SOUTHPASS62           0      0    0       0       G       0                  0     157    33     0   405  0  0   0    0   372
LO019 SOUTHPASS65           0      0    0       0       G       0  33              0     166    24     0   405  0  0   0    0   391
LO020 WESTDELTA30        1949   2152    0   16000 Z     G      25  33              0     185   265     0   958  0  0   0    0   693
LO021 WESTDELTA58           0      0    0       0       G       0                  0     130    20     0   319  0  0   0    0   299
LO022 WESTDELTA73        1962   9000    0    5800 A  SS G      30                  0     163   111     0   584  0  0   0    0   473
LO023 EUGENEIS32         1950      0    0    3300 Z     G       0                  0                 0     0     0  0  0   0    0     0
LO024 STIMBALIER135      1956      0    0    5700 Z     G       0                  0                 0     0     0  0  0   0    0     0
LS001 AVERYISLAND        1942  10000  350    1300       G      33           EX PR  0      34    76     0   211  0 15   0    0   135
LS002 BAYDECHENE         1941   8000   73    3200       G      32            M PR  0      47    63     0   211  0 33   0    0   143
LS003 BAYSTELAINE        1929   8010    0    8400 Z     G      34                  0      68   132     0   384  0  0   0    0   252
LS004 BAYOUSALE          1940   5000   10   10000 A     G      44  16     EX PR  0      36   140     0   338  0102   0    0   193
LS005 BLACKBAYWEST       1953   9600   15    2700       G      34            M PR  0      74    76     0   288  0270   0    0   212

  1          2             3      4     5       6  7  8  9 10 11 12  13    14  15 16      17    18    19    20  21 22  23   24   25
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BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

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  1        2                  3      4     5      6   7  8  9 10 11 12  13   14  15 16     17   18    19   20  21 22 23   24    25

LS006 CAILLOUISLAND         1930   8000  350  20700 Z  55  G        31  23  500  25  0    227  473     0 1344  0  6  0    0   871
LS007 COTEBLANCHEIS         1948   9000   54      0        G        30       EX  PR  0     64   67     0  252  0  0  0    0   105
LS008 DELTAFARMS            1940   9000  270  10200 A      G  W     35       EX  PR  0     12  108     0  230  0  2  0    0   122
LS009 GARDENISBAY           1934   8000  350  11000 Z      G        34        M  PR  0     89  156     0  470  0  4  0    0   314
LS010 GOLDENMEADOW          1938   8000    0  12200 Z      G        30  18    M  PR  0     24  111     0  259  0  0  0    0   148
LS011 GRANDBAY              1938   5920  290  10000 A      G        34  31    M  PR  0     62  143     0  394  0  4  0    0   251
LS012 HACKBERRYEAST         1927   8000 1000   4100 Z      G        23       EX  33  0     20   90     0  211  0  1  0    0   121
LS013 HACKBERRYWEST         1928   8000  890   5000 Z      G        26       EX  27  0     28  112     0  269  0  2  0    0   157
LS014 IOWA                  1931   8000  250   5400 Z      G        31       EX  PR  0     10   90     0  192  0  4  0    0   102
LS015 JENNINGS              1901   6000  350   3600 Z      G        23       EX  PR  0      4  111     0  221  0  4  0    0   110
LS016 LAFITTE               1935   6000  250   8900 Z      G        36  30   EX  29  0     86  199     0  547  0  7  0    0   349
LS017 LAKEBARRE             1929   8000  275  10300 Z      G        31  49   EX  PR  0     59  161     0  422  0  5  0    0   261
LS018 LAKEPELTO             1929   8000    0   5500 Z      G        27        M  PR  0     41   94     0  257  0  0  0    0   165
LS019 LAKESALVADOR          1940   6000  151   2500        G        34        M  PR  0     39   71     0  211  0 19  0    0   140
LS020 LAKEWASHINGTON        1931   8000 2000  13600 Z      G        27  37   EX  PR  0     90  185     0  528  0  1  0    0   343
LS021 LEEVILLE              1931   8000 1402   9400 Z      G        30       EX  PR  0     30  120     0  288  0  1  0    0   168
LS022 PARADIS               1939  10343  300   5300 Z      G        39       EX  PR  0     15   95     0  211  0  4  0    0   116
LS023 QUARANTINEBAY         1937   7000  270  11700 A      G        32       EX  PR  0     43  142     0  355  0  3  0    0   213
LS024 ROMEREPASS            1950   8000  275   4000        G        33        M  PR  0     30   75     0  202  0  6  0    0   127
LS025 VENICE                1937   8000 1149   6400 Z      G        45       EX  30  0     36  149     0  355  0  1  0    0   206
LS026 VINTON                1910   5000    0   3700 Z      G        23       EX  PR  0     24  116     0  269  0  0  0    0   153
LS027 WEEKSISLAND           1945   9000    0   5900 Z      G        35  18   EX  PR  0    106  104     0  557  0  0  0    0   373
LS028 WESTBAY               1940   9000  486  11200 Z      G        31  27   EX  PR  0     79  162     0  463  0  3  0    0   301
LS029 COTEBLANCHBAY         1940      0    0   5900 Z      G         0                0    121  129     0  460  0  0  0    0   351
LS030 ERATH                 1940      0    0   5900 A      G         0                0           0     0    0  0  0  0    0     0
LS031 TIMBALIERBAY          1933      0    0  11700 Z      G         0     7500  25  0           0     0    0  0  0  0    0     0
NM001 CAPROCKCEAST          1940   8000   15  30300 A      G        38 107 2500  21  0      8   92     0  413  0 43  0    0   321
NM002 DENTON                1949   9488   75   4600 A      C        41      120  10  0     19  121     0  578  0171  0    0   457
NM003 EMPIREABO             1957   6014   16   9800 A      G        44 115    M   8  0     81   89   947  732  0892  0    0   858
NM004 EUNICE                1929   3530   50  23000 A      G        32      300  12  0     12  118     0  537  0 45  0    0   419
NM005 HOBBS                 1928   4050   30  14800 A      W        34 141  500  15  0     43  222   807 1094  0113  0    0   555
NM006 MALJAMAR              1926   3600   50  23000 A      G        37 100  470  11  0     74   91   376  631  0 29  0    0   285
NM007 MONUMENT              1929   5180   20  25000 A      C        35 139    P   8  0     30  210     0  911  0252  0    0   781
NM008 VACUUM                1929   4300   20  21900 A   1  C     P  35 100 2000  10  0    142  258     0 1652  0410  0    0  1394
NM009 JALMAT                1929      0    0  92300 M      G         0                0           0     0    0  0  0  0    0     0
ND001 BEAVERLODGE           1951   8550  100  16000 A      G        42  24    P   8  0     28   72     0  406  0 34  0    0   334
ND002 TIOGA                 1952   7990   40  22600 A      G        38  74   30  12 35     32   68     0  406  0 40 57  547   333
OK001 ALLEN                 1913   1101    0  10300 A      G        36                0     18  122     0  433  0  0  0    0   311
OK002 AVANT                 1904   1400    0  12600 A      G        36                0      3  106     0  337  0  0  0    0   231
OK003 BOWLEGS               1927   2920    0   3200 A  55  G        39                0     10  155     0  510  0  0  0    0   355

  1        2                  3      4     5      6   7  8  9 10 11 12  13   14  15 16     17   18    19   20  21 22 23   24    25
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FIGURE III-3 (continued)

BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
OK004	BURBANK	1920	2800	60	36900	M		G			38	24			0	44	496	0	1669	0	0	0	0	1173
OK005	CEMENT	1917	8000	30	18500	A		G			34				0	19	137	0	482	0	0	0	0	345
OK006	CUSHING	1917	1475	40	36200	A		G	W		34	25	P	PR	0	18	457	0	1468	0	36	0	0	1011
OK007	EARLSBORO	1930	2960	15	7600	A	SS	G			37				0	5	215	0	680	0	0	0	0	465
OK008	EDMONDWEST	1943	6938	0	43000	M		G			42				0	6	154	0	494	0	0	0	0	340
OK009	EOLA-ROBBERSON	1921	1300	0	5400	A		G			30				0	40	100	0	433	0	0	0	0	333
OK010	FITTS	1932	1150	0	6000	A		G			37		P		0	14	146	0	494	0	0	0	0	348
OK011	GLENNPOOL	1905	815	0	27400	A		G			37	27			0	15	335	0	989	0	0	0	0	634
OK012	GOLDENTREND	1945	6210	40	96000	A		G			38	14			0	115	314	0	1542	0	0	0	0	1150
OK013	HEALDTON/HOXBAR	1913	1000	60	7100	A	SS	G	W		31	93	500	23	0	40	280	674	989	0	52	0	0	394
OK014	HEALDTON/ARBUCK	0	3900	250	1800	A	DD	G	W		37		150	15	0	56	0	0	0	0	0	0	0	0
OK015	HEWITT	1919	900	10	17000	A		G			35	84			0	35	206	0	745	0	0	0	0	537
OK016	LITTLERIVER	1937	2280	50	3700	A	SS	G			37				0	6	159	0	510	0	0	0	0	351
OK017	OKLACITY/WILCOX	1928	6500	114	7900	A	SS	G			40	16		21	1	20	730	1072	[illegible]	0	23	49	1453	342
OK018	OKLACITY/ARBUCK	0	0	109	2500	A	SD	W			0				0	51	0	75	0	0	0	0	0	75
OK019	OKLACITY/OILCRK	0	0	40	4500	A	SS	C			0			18	10	52	0	162	0	0	64	90	226	162
OK020	SEMINOLEGREATER	1926	2289	0	8200	A	SS	G			38				0	13	197	0	649	0	0	0	0	452
OK021	SHOVELTUM	1914	2500	0	106000	A	SS	G	W	P	26		8600		0	215	935	0	3553	0	0	0	0	2618
OK022	SOONERTREND	1945	7000	0	346000	A	SS	G			36				0	72	178	0	772	0	0	0	0	594
OK023	STLOUIS	1925	3500	0	26100	AM		G			35	11			0	11	214	0	695	0	0	0	0	481
OK024	TONKAWA	1921	2600	0	4300	A	SS	G			40		P		0	2	135	0	423	0	0	0	0	288
OK025	ELKCITY	1947	0	0	12200	A		G			0				0		0	0	0	0	0	0	0	0
UT001	ANETH	1956	5670	50	18100	A	LM	W			41	10	100	10	0	71	244	740	1285	0	71	0	0	496
UT002	REDWASH	1951	5400	200	0	N	SS	G			28		EX	15	0	54	86	484	571	0	0	0	0	398
UT003	MCELMOCRK	0	5400	0	5000		LM	G			40	10			0		0	0	0	0	0	0	0	0
UT004	RATHERFORD	0	5940	0	8800		LM	G			41	11			0		0	0	0	0	0	0	0	0
UT005	WHITEMESA	0	5500	0	3400			G			41				0		0	0	0	0	0	0	0	0
UT006	ALTAMONTTREND	0	0	0	0			G			0				0	989	11	0	4090	0	0	0	0	4067
WY001	ELKBASIN/MADISN	1946	4700	336	5100	A		G	W		28		200	12	0	88	452	1240	2570	0	47	0	0	783
WY002	ELKBASIN/FRONTR	1915	1400	400	1300	A	SS	G	B		43			26	0	51	0	71	0	0	7	0	0	71
WY003	ELKBASIN/TENSLP	1942	4000	77	500	A	SS	G	W		28		1190	14	0	52	0	34	0	0	81	0	0	34
WY004	GARLAND/TENSLP	1906	2000	60	1500	AF	SS	W	W		28			24	0	32	103	23	643	0	-49	0	0	-60
WY005	GARLAND/EMBAR	0	3300	59	1500	AF	LM	W	W		32		530	19	0	51	0	83	0	0	64	0	0	63
WY006	GRASSCRK/FRONTR	1914	1000	20	1700	A	SS	G	W		40		350	22	0	31	134	163	785	0	45	0	0	26
WY007	GRASSCRK/CURTIS	1952	4400	55	5600	A	SS	W	B		27		1200	17	0	56	0	115	0	0	73	0	0	110
WY008	HAMILTONDOME	1918	2000	120	2400	AF	SL	C			20	300	500	18	0	43	172	0	1023	0	212	0	0	851
WY009	HILITE	1969	9578	0	0			G			41				0	101	34	0	643	0	0	0	0	609
WY010	LANCECRK/B.SUND	1918	2659	64	1700	A	SS	W	B		37	13	2500	22	0	3	104	131	509	0	15	0	0	27
WY011	LOSTSOLDIER/TSL	1930	3900	250	1200	AF	SS	C	B		35	120	1370	13	0	31	134	190	765	0	19	0	0	56
WY012	LOSTSOLDIER/MAD	1948	5400	188	700			W	W		35		180	12	0	51	0	112	0	0	91	0	0	112
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25

FIGURE III-3 (continued)

BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

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  1          2              3      4     5      6  7  8  9 10 11 12  13     14 15 16     17    18    19    20 21 22 23    24    25

WY013 LOSTSOLDIER/CMB  1948      0    94    700         G  W     21          740 10  0     52     0    50     0  0 98  0     0    50
WY014 OREGONBAS/TNSLP  1912   3050    60   7600 A   SS  G  W     21 300     1500 16  0     72   218   492  1380  0 48  0     0   274
WY015 OREGONBAS/EMBAR  1927   3354    38   7600 A   LM  G  W     22 300      100 14  0     51     0   363     0  0116  0     0   363
WY016 SALTCRK/1STWALL  1906   3300    80   4000 AF  SS  C  B     36          800 15  0     80   514   206  2827  0-83  0     0  -308
WY017 SALTCRK/2NDWALL     0   3700    59  15400 AF  SS  G  W     38         1000 18  0     51     0   637     0  0 54  0     0   687
WY018 SALTCRK/2WALLSO     0   3700    25   6100 AF  SS  C  W     37          300 18  0     52     0   109     0  0 51  0     0   109
WY019 BIGMUDDY/WALLCK  1916   3100    38   3500     SS  G  B  S  35          350 10  0            0    91     0  0  0  0     0     0
WY020 CLARETON/TRUE       0      0    10  22000         G        40          140  7  0            0   100     0  0  0  0     0     0
WY021 COTTONWDCRK/PHO     0   7270    20  14200     LM  G  B     30          160 10  0            0   182     0  0  0  0     0     0
WY023 LITTBUFFBAS/TSP  1914   4900    28   1800     SS  G  W     21          740 10  0            0   180     0  0  0  0     0     0
WY024 PATRICKDRW/MCNL     0      0    21   1500         G  W     43          360 20  0            0   133     0  0  0  0     0     0
WY025 STEAMBOATBUT/TS  1943   6771   200   1300     SS  G  W     21          300 13  0            0   297     0  0  0  0     0     0
WY026 WERT//TENSLEEP   1920   5880   150   1200     SS  G  B     35          230 11  0            0   100     0  0  0  0     0     0
WY027 WINKLEMANDM/TSP  1944   2900   160   1000     SS  G  W     25              15  0            0   131     0  0  0  0     0     0
T1001 CHARLOTTE        1944   5200    25   6900         G  W     38          210 20 50           41   200     0  0 59 35   134   159
T1002 JOURDANTON       1946   7300    40   4300         W  G     38          225 20 29           10   200     0 65 71 67   189   190
T1003 SOMERSET         1911   1500    15  14000         G  W     33          850 29 48           14   149     0 40 29 49   246   135
T1004 LULING-BRAYON    1922   1900   100  11300 NF      W        36         2000 28  0     16   144   534   606  0 16  0     0   390
T1005 LYTTONSPRINGS    1925   1600    15   2000         G  W     37           70 25  0           10    44     0  0 58  0     0    34
T1006 SALTFLAT         1928   2300    60      0         G  W     36           10 19  0           68   471     0  0  0  0     0   403
T1007 BIGWELLS         1969   5420    15  25400         G  B     34          100 19 54    133    21 (178)  584 45 28 42   258   157
T1008 BIGFOOT          1949   3300    15  12000         G  W     44           30 23 50           23   135     0 35 35 43   161   112
T1009 PEARSALL/AUSTIN  1936   5330   100   3500         C  W     33            P  F  0            6     0     0  0  0  0     0     0
T1010 PEARSALL/NAVARR  1934   3920    17   1300         G        26                 0            7     0     0  0  0  0     0     0
T1011 DARSTCREEK       1929   2300   125   5600 NF      W  W     34         2000 21  0     22   129   297   568  0 15  0     0   169
T1012 CALLIHAN         1918    900    18   1000         G        21                 0            2    33     0  0  0  0     0    31
T1013 EZZELL           1936   1490    10   2500         W        20              30  0            7    30     0  0 40  0     0    23
T1014 JACOBS           1935   1000     7   1200         G        21                 0            5    15     0  0  0  0     0    10
T2001 GRETA            1934   3540    10   9300 A   SS  W  W     30           EX 30 20     52   108     0   355  0114 30   173   247
T2002 REFUGIO          1917   2800    25  17000 A   SS  W  W     32         6000 29  0      5    95     0   222  0 13  0     0   127
T2003 TOMOCONNOR       1934   5700    25  14800 A   SS  C  W     34  15     6240 30 14    257   443     0  1554 60129 35   741  1111
T2004 WESTRANCH/GLASS  1938   5550    20   7300 A   SS  G  W  H  31  90     3940 29 40    177   248   144   943 36-32-15   197  -104
T2005 WESTRANCH/98-A   1940   6100    32   3000 A   SS  C  W     40         4950 30 40     51     0    90     0  0 40 60   134    90
T2006 WESTRANCH/WARD   1939   5700    13   4200 A   SS  G  W     31        12280 31 42     52     0    69     0  0 53 56    76    69
T3001 ANAHUAC          1935   6850    60  10900 Z   SS  G  C     34  15    10850 28 24    126   224     0   714  0 34 60  1030   490
T3002 BARBERSHILL      1918   8000    40   1700 Z   SS  W        29        10000 30  0     12   123     0   275  0 96  0     0   152
T3003 CONROE           1931   5105    15  12300 Z   SS  C        35  33     7500 28 23    178   479     0  1340  0215-43   309   861
T3004 DICKISONGILLOCK  1934   9000     0   1800 7   SS  G        34           EX 30  0     46   104     0   306  0  0  0     0   202
T3005 GOOSE&FASTCREEK  1968   4700    30   3700 Z   SS  W        25         6000 28 28     66   129     0   398 54111 19   174   269
T3006 HASTINGSE&W      1934   5500   600   7200 Z   SS  W        31  19     8800 32 20    223   453     0  1379  0  9 76  8500   926

  1          2              3      4     5      6  7  8  9 10 11 12  13     14 15 16     17    18    19    20 21 22 23    24    25
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FIGURE III-3 (continued)

BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
T3007	HIGHISLAND	1922	5000	80	7000	Z	SS	W			28		15500	32	0	22	128	0	306	0	13	0	0	178
T3008	HULLMERCHANT	1918	5000	0	15200	Z	SS	G			30	35	2500	28	0	14	191	0	428	0	0	0	0	227
T3009	HUMBLE	1905	5000	30	7500	Z	SS	G			30			PR	0	31	159	0	388	0	52	0	0	229
T3010	MAGNETWITHERS	1936	5500	15	7900	Z	SS	W			26		17000	28	25	50	75	166	255	0	35	46	193	91
T3011	OLDOCEAN	1934	8600	0	13000	Z	SS	W			38	21	10000	25	0	10	170	0	265	0	0	0	0	145
T3012	RACCOONBEND	1928	4000	15	5100	Z	SS	G			33		EX	24	0	38	87	0	255	0	118	0	0	165
T3013	SOURLAKE	1902	8000	15	13200	Z	SS	G			38		20000	33	30	9	116	0	255	70	27	47	355	139
T3014	SPINDLETOP	1901	5000	0	1600	Z	SS	W			25		EX	30	0	4	151	0	316	0	0	0	0	165
T3015	THOMPSON	1931	4000	20	7400	Z	SS	W			32	20	11000	26	30	162	338	1887	1020	0	519	-43	209	1549
T3016	TOMBALL	1933	5500	20	19900	Z		W			40			PR	0	33	97	0	265	0	22	0	0	168
T3017	WEBSTER	1931	5750	150	4200	Z	SS	C			29		11500	31	0	208	367	992	1173	0	41	0	0	625
T3018	WESTCOLUMBIA	1915	8000	30	6800	Z	SS	W			26			30	0	15	155	0	347	0	40	0	0	192
T3019	WILLOCKSOUTH	1948	8200	0	5900		SS	W	W	2	38		9000	27	22		33	130	0	0	0	0	0	97
T3020	PIERCEJUNCTION	1921	5000	20	3800	Z		C			34		800	30	40		86	0	0	60	0	0	0	0
T3021	KATY	1942	6400	14	0			W			0		10530	30	20		4	0	0	0	0	0	0	0
T3022	MANVEL	1931	5800	0	0			W			0		5000	28	0		27	153	0	0	0	0	0	125
T3023	OYSTERBAYOU	1941	8294	0	0			G			36				0		90	0	0	0	0	0	0	0
T3024	LIBERTYSOUTH	1925	7000	0	5600	Z		G			47				22		73	0	0	0	0	0	0	0
T3025	SUGARLAND	1929	3900	0	0			G			27				0		66	0	0	0	0	0	0	0
T4001	AGUADULCESTRATT	1928	6450	24	20000	A	SD	G			37	8	2200	21	40	37	133	0	481	0	45	43	469	348
T4002	BORREGAS	1945	5100	15	6000	A	SS	G			42		720	23	55	31	104	0	332	34	173	-20	72	278
T4003	KELSEY	1938	6000	16	19800	A	SS	G	B		39		2000	25	30	48	102	0	424	0	52	53	430	322
T4004	PLYMOUTH	1935	4610	50	4500	A	SS	W			38	5	4000	25	31	10	115	0	354	51	55	43	301	239
T4005	SEELIGSON	1937	5182	25	14000	A		C			41		4000	23	39	68	257	0	920	40	106	20	381	663
T4006	TIJ-CAN-BLUCHER	1939	7000	20	10200	A	SS	G	W		40		6000	28	22	75	90	0	467	50	65	58	346	377
T4007	WHITEPOINTEAST	1938	5000	15	4600	A	SS	C			35		EX	PR	0	12	98	0	311	0	159	0	0	213
T4008	ALAZANNORTH	1958	7208	14	6000	A		G	G		44		3800	25	34		22	46	0	0	15	52	108	24
T4009	GOV.WELLSNORTH	1928	1568	0	8500	M	SS	G		C	22		8000	32	0		75	0	0	0	0	0	0	0
T4010	GOV.WELLSSOUTH	1930	1750	20	4500	S		G			23		6000	30	35		15	40	0	45	12	58	136	25
T5001	MEXIA	1920	3100	40	3600	AF	SS	W	W		35			25	0	3	107	0	209	0	35	0	0	102
T5002	POWELL	1895	3300	40	2600	NF	SS	G	W		35			PR	0	1	129	0	247	33	58	0	0	118
T5003	VAN/WOODBINE	1929	2700	250	4500	AF	SD	C	W		33	86	10000	29	9	164	387	600	1047	36	8	76	2303	213
T5004	VAN/LEWISVILLE	1929	2800	60	4500	AF	SD	G	W		33		1000	26	35	51	0	30	0	35	6	65	354	30
T6001	EASTTEXAS	1930	3600	40	135700	S	SS	W	B		38	31	3500	25	14	1906	4094	7000	13200	0	28	47	9054	2906
T6002	FAIRWAY	1960	9900	20	22600	P	LM	G	B	H	47		200	11	27	107	92	400	438	52	80	49	282	308
T6003	HAWKINS	1940	4500	250	13900	A	SS	G	W	2	52	192	50002	73	0	369	457	1434	1817	0	5	0	0	977
T6004	NECHES	1953	4572	25	9300	AF	SS	C			30		8000	24	42	50	50	0	220	0	39	46	251	170
T6005	QUITMAN	1942	6250	35	3200	A	SS	G			41			21	0	37	73	0	242	0	93	0	0	169
T6006	TALCO	1936	4250	30	9500	NF	SS	W			23	200	5000	25	11	41	229	0	594	0	66	48	492	365
T6007	TRIXLIX	1958	3650	25	800	A	SD	G		C	23		5000	29	35		8	0	0	0	0	0	0	0
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25

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FIGURE III-3 (continued)

BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

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  1        2                 3      4     5      6  7  8  9 10 11 12  13   14 15 16      17    18    19    20  21 22 23    24    25

T6008 NEWHOPE              1943   7400    0   5800 A     G          42                 0          40     0     0  0  0  0     0     0
T6009 HAYNES               1954   5925   18   8000    LM G W        40        250 16 32          11    50     0 40 22 62   122    39
T0001 BIGLAKE              1923   2900   60   5600 A  DO G          36  35    200 18 20      11   124     0   937 43173 54   375   813
T0002 MCCAMEY              1925   2200   75  20000 A  DO G W P      28         25  9 17       8   122     0   902 81 74 71   869   780
T0003 PEGASUS/SANANDR      1949   5600   35   2500 A  SS G W M      33  33    100 19 46      33   108     0   979  0675-30    70   871
T0004 PEGASUS/ELLENBG      1954  13100  436   5800 A  DO G          54   9    180  3 30      51     0     0     0  0  0  0     0     0
T8001 ANDECTOR             1946   4220   35   5000 A  SS G          36  50     40  7 30      71   115     0   735  0652-51    67   520
T8002 BLK31/GRAYBURG       1945   3200    7   1700 A  SS C B H      27 100        16 30      58   132     0   750  0187324    10   618
T8003 BLK31/ELLENBURG      1956  10330  173   2000 A  LM C          43                2  0      51     0     0     0  0  0  0     0     0
T8004 COWDENNO/GRAY        1930   4300  125  37000 A  SS G W M      32         30 12 16      76   249     0  1284 60 24 78  3617  1035
T8005 COWDENNO/HOLT        1939   5100   70   7000 A  LM G          36         70 12 20      51     0     0     0  0  0  0     0     0
T8006 COWDENSOUTH          1930   4550  100  21600 A  LM C W        35 177     40  5 30     133   267     0  1580  0157 38   597  1313
T8007 DOLLARHIDE           1945   8500  100   7700 AF LM C          40  25    400  6 22      71   139     0   829 65193 39   280   690
T8008 DUNE                 1938   3250   70  34800 A  DO G N        32 148    300  5 35      90   110     0   790 51 72 53   614   680
T8009 EMMA-TRIPLEN         1937   5405   38   7600 A  LM C          37  40    370  5 40      23    92     0   454  0323-22    67   362
T8010 FUHRMAN-MASCHO       1930   6000   25  35500 A  LM G          31 200     06  8 40      29    71     0   395  0 59 47   331   324
T8011 FULLERTON            1941   6000   70  31600 A  LM G          35 209    750 10 50      75   225     0  1185  0 56 37   858   960
T8012 GOLDSMITH            1935   7200   30  66100 A  LM C          35 190    150  9 25     133   542     0  2666 43153 36  1038  2124
T8013 HENDRICK             1926   2500   30  27000 A  LM W          29 160     50  9  0       4   251     0  1007  0134  0     0   756
T8014 HOWARDGLASSCOCK      1925   1400   20  67900 A  SL G W P      30 100    250 16 30      79   296     0  1481  0 70 52  1180  1185
T8015 IATANEAST            1925   2600   70  33400 A  DO G          27         22  9 22      47    78     0   494 60 25 73  1273   416
T8016 JORDAN               1937   3400   89  25400 A  LM C          38  34    160 12 35      34    96     0   513  0 20 60  1368   417
T8017 KERMIT               1928   2900   70  61600 A  LM C          34 150    100 10 40      20   110     0   513  0 12 57  2007   403
T8018 KEYSTONE/COLBY       1930   3140   25  25200 A  SS G          38 150     50 12 35      58   262     0  1264  0171 20   381  1002
T8019 KEYSTONE/ELLENB      1943   5650  300   7200 A  DO C          43  14    400  3 10      51     0     0     0  0  0  0     0     0
T8020 KEYSTONE/HOLT        1943   4700   55   5700 A  DO C          40        580 17 32      52     0     0     0  0  0  0     0     0
T8021 MCELROY              1926   2700  100  30000 A  DO G          31 240    200 15 25      73   286   800  1418  0 15 67  2618   514
T8022 MEANS/GRAYBURG       1934   4300  200  18500 A  DO G          29        290  8 35      78   132   365   829  0 10 59  1493   233
T8023 MEANS/QUEEN          1954   4100    7  17000 A  SS G          33        400 15 35      51     0    91     0  0 66 65    90    91
T8024 MIDLANDFARMS         1944   6300   80  15000 A  LM W    H     41  05    100 12  7      62   161     0   881 46 64 79  1039   720
T8025 PENWELL              1929   4000   60  17400 A  LM G          35 200    100  8  0      18    82     0   395  0 48  0     0   313
T8026 SANDHILLS/MCKNE      1944   3420   14  27100 A  DO G          35                   0      67    89     0   616  0  0  0     0   527
T8027 SANDHILLS/TOBB       1930   4500  200  27100 A  DO C W P      35        150 10 40      51    71     0   482  0 10 58  2523   411
T8028 SHAFTERLAKE          1938   4482  110  14200 A  LM G          34         50  7 23      33    67     0   395  0 39 69   653   328
T8029 TXL                  1944   4525   70  19300 A  LM G          40  16    250 10 20      36   229     0  1047  0 78 58   839   818
T8030 WADDELL              1927   3500  120  18900 A  LM G W H      34 217     30 10 36      35    75     0   434  0 20 60  1126   359
T8031 WARDSOUTH            1929   2200   18  41700 M  SS G W        34        200 20 35       5    96     0   399 40 26 57   757   303
T8032 WARDESTESNORTH       1929   2700   40  85800 A  SS G K        32 123    250 22 40      79   296     0  1481 48 20 55  3515  1185
T8033 YATES                1926   1150  200  25200 A  LM G W        29 155     50 17  0    1030   569     0  6316  0 86  0     0  5747
T8034 CROSSET              1944   5324   50   6500 S  LM G    2     42         50 20 35            21    71     0  0 10 61   328    50

  1        2                 3      4     5      6  7  8  9 10 11 12  13   14 15 16      17    18    19    20  21 22 23    24    25
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FIGURE III-3 (continued)

BIG FIELD DATA FILE: COMPUTER PRINT-OUT LISTING

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1     2                   3      4     5        6 7   8 9 10 11 12  13    14 15 16       17    18    19    20 21 22 23    24    25

TR036 GERALDINE        1956   2560    15     5400       G       42       490 23 45            14   110     0  0 38 49   133    96
T0037 THREEBAR         1945   5400    70     5400 S     G       41       540 20 27            28    83     0 70  9 68   428    55
TA001 ANTON            1944   5600   250     9000 A  DO G W     28       170  8 30      44    66     0   356  0 21 65   978   290
TA002 COGDELL          1949   6796    60    15000 R  LM G       41  40   160 10 37     155   165   420  1037  0 37 39   440   755
TA003 DIAMONDM         1949   2430    45    12500 R  LM G       35  20   200 15  0      92   183     0   891  0108  0     0   708
TA004 KELLYSNYDER      1948   6900   213    52000 R  LM G W  2  42  30   194  8 35     639   611  2930  4050 64 32 56  4466  2219
TA005 LEVELLAND        1945   4800    64    88000 A  LM G W  H  29 212    20 10 40     116   209     0  1053 65 19 55  2622   844
TA006 PRENTICE         1950   6430   100     9000 A  DO G W     27        23 10 41      58    92   192   454  0 14 47   412   100
TA007 RUSSELL/DEVONIA  1948  10900   140     6200 A  DO C W     34       141  6 13      29   106   182   437 71 19 61   352    76
TA008 RUSSELL/CLEARFO  1942   7350    55     9700 A  DO G W     37        15  5 26      51     0     0     0  0  0  0     0     0
TA009 SALTCREEK        1950   6350   100     9200 R  LM G W  H  39  60   105 12 30     128   102   372   745  0 32 58   600   270
TA010 SEMINOLE         1936   5200   150    16400 A  DO G W     35 186   312 13 11     131   184   970  1021 71 32 82  2208   786
TA011 SLAUGHTER        1936   4950    55   113000 M  DO G W H2  32 190   300 12 11     287   503     0  2570 65 35 80  5150  2057
TA012 SPRAYBERRY/COLO  1949   7452    60   134100 M  DO G W  H  42                35     169   341     0  1052  0  0  0     0  1311
TA013 SPRAYBERRY/PERM     0      0     0        0 M  DO C       36        10 12 37      51     0     0     0  0  0  0     0     0
TA014 SPRAYBERRY/SAND     0   5620     0        0 M  SS G       40       140 16 30      52     0     0     0  0  0  0     0     0
TA015 SPRAYBERRY/CLEA     0   7174     0        0 M     G       40                 0      53     0     0     0  0  0  0     0     0
TA016 WASSON           1936   5100   180    71300 A  DO G W  2  33 101    25 10 20     799   700  2120  4857 62 14 73  7956  1403
TA017 WELCH            1936   4900    70    16100 A  LM G       33  15    50 10 24      74    76   268   486 68 22 67   665   192
TA018 REEVES           1957   4866    45     4800 A  DO G       33        28 12 36            14    88     0 52 37 57   129    74
TA019 ADAIR            1950   8500   100    28400 R  LM G       42       277 12 24            52   100     0 57  2 74  2009    48
TA020 HARRIS           1949   5920    41     5200 A  SD G       31       180  9 34            20    35     0  0 10 53    98    15
T9001 KMA              1931   3700    30    30000 A  SS G B     41       600 15 20      22   163     0   729  0 54 64   838   566
T9002 WALNUTBEND/HUDS  1938   4250    15     1800 A  SS G W     30      1380 20 34      49    91    50   552  0-98151    28   -41
T9003 WALNUTBEND/WING  1943   5483    21     1500 A  SS C W     32      3090 17 16      51     0    48     0  0116 84    35    48
T9004 WALNUTBEND/REG   1938   4755    23     2700 A  SS C W     36      1760 19 17      52     0   111     0  0139 83    66   111
T9005 W.BURKBURNETT    1912   1700     0    11000 R  SS G B     42                 0             0     0     0  0  0  0     0     0
T9007 HULL-SILK-SITES  1939      0     0     7500 A  SS G       40       213 16 36             5     0     0  0  0  0     0     0
T0001 PANHANDLE        1910   2900   100   200000 A  SD G W  S  38  10             0     156  1259     0  6368 50  0  0     0  5109

1     2                   3      4     5        6 7   8 9 10 11 12  13    14 15 16       17    18    19    20 21 22 23    24    25
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in excess of 100 million barrels. For the Texas fields, most of the data is based on the hearings of the Texas Railroad Commission as described by the Texas Statehouse Reporter [27]. Other Texas sources included Texas Railroad Commission annual publications [14, 30] and the report of the Texas Petroleum Research Council [31]. For Louisiana fields, the primary source is the Louisiana Department of Conservation report on secondary and tertiary projects [15]. The rather complete file on Wyoming is based on a Bureau of Mines report on waterflood projects in that state [19]. Data for the other states were based on a wide variety of sources, principally the annual reports of the International Oil Scouts [32], The International Petroleum Encyclopedia, the AAPG Report, Geology of Giant, Petroleum Fields [33], and individual journal and magazine articles and publications.

The data was rife with discrepancies and gaps. Discrepancies were resolved on the basis of our best judgement. Where we were unwilling to make a "best guess", the corresponding element in the data file was left blank.

Estimation of Original Oil-in-Place

One of the most difficult and yet most important pieces of data is original oil-in-place. In some cases we were fortunate to find direct quotes. In other cases (principally California) it proved possible to use the estimate of the original oil-in-place discovered for the initial year of discovery of the field in the relevant district and state given in the API/AGA reserves annual. The underlying premise here is that most of the oil discovered in that district for that year would have been in the giant.

This estimation process seemed to work well enough in California. However when applied to Texas there were glaring discrepancies, all on the low side. It appears that in allocating original oil-in-place to year of discovery, the Texas API representatives have either used the year of discovery of a particular formation, reservoir, or some other sub-field unit. Thus, for Texas at least, this approach proved futile.

Even after aggressively extrapolating from the data, we found that for the bulk of the fields in our sample, we still had no estimate of original oil-in-place. In order to obtain at least a preliminary "ballpark figure" of OOIP for these fields, two separate estimation procedures were followed:

(i) *Estimate I*

For those fields for which we had both cumulative production and an OGJ recoverable estimate, an estimate of the original oil-in-place was obtained by multiplying the sum of the cumulative production and OGJ recoverable[1] by the ratio of the API estimate of original oil-in-place for the relevant district to the API ultimate recovery for that district as given in the API/AGA annual.[34] The rationale for this procedure is that fields in the same district tend to have the same reservoir characteristics and thus this ratio is likely to be about the same for all fields in the district. While this argument is somewhat tenuous, there is a definite tendency for fields in the same district to have similar characteristics, as even a casual investigation of Figure III-3 will reveal. The result of this process has been listed in Figure III-3 in column 20. It is interesting to compare by inspection the differences between column 19 (quoted OOIP) and column 20 (Est.I-OOIP). Thus, in aggregate terms, this process probably somewhat overestimates the original oil-in-place.

(ii) *Estimate II*

The second original oil-in-place estimating process was undertaken for those fields for which we had an estimate of area, thickness, porosity, and percentage connate water. The estimate made was simply the available pore volume assuming a formation volume factor of 1.05, typical of shallow depleted fields. This estimate proved wildly erratic, pointing up once again the generally poor quality of our volumetric data. As a result, this estimate was of little value and was subsequently ignored.

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[1] This sum corresponds to OGJ estimate of ultimate recovery.

Estimation of Current Oil Saturation

Figure III-3 contains three estimates of the current oil saturation; columns 21,22 and 23, respectively. This is a most important variable in determining the economics of secondary and especially tertiary recovery. Unfortunately, of all the major reservoir characteristics, it is probably the one about which we know the least. If column 21 is non-zero, it implies an estimate was available from the literature. Unfortunately, this was the case for only 40 fields. The value in column 22 was obtained by taking the ratio of our best estimate of the remaining oil-in-place to the pore volume for those fields for which area, thickness, and porosity were known. However, due to errors in the volumetric data discussed above, this estimate also proved wildly erratic, often greater than 100, indicating that either the thickness or area values were low. Consequently this estimate has to be regarded as virtually useless. A third estimate was obtained for those fields for which in addition to the area, thickness, and porosity, the connate water was also known. Here the estimate of oil saturation represents the ratio of the volumetric estimate of remaining oil-in-place to the pore volume. This third estimate suffered from the same problems as the second estimate and cannot be used. In short, we found ourselves sadly lacking in current oil saturation data for these fields.

Estimation of Remaining Recoverable Oil-in-Place

The final column in Figure III-3 contains our best estimate of the remaining oil-in-place (RROIP) for each field. If we had quoted data on the original oil-in-place, RROIP could easily be computed as the difference between the quoted OOIP and cumulative production. Otherwise it must be estimated as the difference between estimated OOIP and cumulative production.

FIGURE III-4

OIL AND GAS JOURNAL* SURVEY OF CURRENTLY OPERATING AND RECENTLY ABANDONED SOPHISTICATED** OIL RECOVERY PROJECTS

Field	State	County	Oper.	Type project*	Pilot or field-wide (FW)	Project area, acres	Start date	Pay zone	Type	Porosity, %	Permeability, md	Depth, ft	— Reservoir oil —		Prev. prod.	Resid. oil sat'n. at start, %	Est. resid. oil sat'n. at end, %	Project's maturity	Project's status	Profitable?
Irma	Ark.	Nevada	Mobil	Comb.	Pilot§	40	9/69	Nacatoch	Sandstone	35	2,000	1,700	14	7M @ 90	Prim.	50	40	Terminated	Disc.	No
Smackover	Ark.	Union	Gulf	Comb.	Pilot§	160	1/70	Nacatoch	Sandstone	33	1,000	2,000	20	74 @ 110	Prim.	55	5	Terminated	Disc.	No
Lost Hills	Calif.	Kern	Mobil	Comb.	FW	140	4/61	"300"	Sandstone	37	5,900	300	16.1	410 @ 95	Prim.	99	80	Half finished		
Midway Sunset	Calif.	Kern	ARCO	Comb.	Pilot§	15	8/68	Potter	Sandstone	32	3,000	1,750	17	200 @ 100	SS			Terminated	Disc.	No
Midway Sunset	Calif.	Kern	Chanslor	Comb.	Pilot¶	20	2/72	Potter 60'	Sandstone	35	3,500	1,550	12	283 @ 140	SS	90	65	Just started	Prom.	Yes
Midway Sunset	Calif.	Kern	Chanslor	Comb.	Pilot	60	12/70	Spellacy 60'	Sandstone	35	3,000	600	14	97 @ 140	Prim	58	65	Just started	Prom.	
Midway Sunset	Calif.	Kern	Mobil	Comb..	FW	390	1/67	Inter Webster	Sandstone	33	2,600	1,600	14	600 @ 113	Prim.	89	80	15% finished		
Midway Sunset	Calif.	Kern	Mobil	Comb.	FW	150	1/60	Moco	Sandstone	36	1,500	2,700	14.5	110 @ 125	NR	99	60	65% finished		
Midway Sunset	Calif.	Kern	Mobil	Comb.#	FW	2,381	6/64	Tulare	Sandstone	35	3,000	1,000	13.6	1.3M @ 90	Prim.	94	65	20% finished		
Brea Olinda	Calif.	Orange	Union	Comb.	Pilot¶	31	3/72	Miocene	Sandstone	29	300	3,500	22	20 @ 135	Prim.	66	45	20% finished	Prom.	Yes
West Newport	Calif.	Orange	Gen'l. Crude	Comb.	FW	400	3/58	Puente	Sandstone			1,200	15	1M @ 100	Prim.	90	50	30% finished	Succ.	Yes
Russell Ranch	Calif.	Santa Barbara	ARCO	Comb.	Pilot	20	4/71	Dibblee	Sandstone	24	102	3,500	32	0.99 @ 140	WF			Just started	TETT	
Robinson	Ill.	Crawford	Marathon	Comb.	Expanded	130	8/61	Robinson Sd.	Sandstone	19.8	350	1,000	23-34	18-80 @ 60	WF	35-45		Nearing completion	...	...
Bellevue	La.	Bossier	La Brea	Comb.	Pilot	13	4/70	Nacatoch	Combination			325	18.6		Prim.				Succ.	
Bellevue	La.	Bossier	Getty	Comb.	FW	600	9/63	Nacatoch	Sandstone	38	300	350	19	500 @ 80	Prim.	93		20% finished	Succ.	Yes
Bellevue	La.	Caddo	Citgo	Comb.	Pilot¶	10	3/71	Nacatoch	Sandstone	31.2	1,000	400	19	226 @ 60	Prim.	95	68	Half finished	Succ.	No
Shoreline	La.	Caddo	Kirby	Comb.	Expanded Pilot	60	6/73	Nacatoch	Sandstone	35.2	606	1,050	22	280 @ 80	Prim.	95	40	Just started	Prom.	No
May Libby (Delhi Unit)	La.	Richland	Sun	Comb.	Pilot§	40	8/66	Upper Cret.	Sandstone	31.2	1,069	3,400	40	3 @ 135	WF	47	44.6	Terminated	Prom.	No
W. Heidelberg	Miss.	Jasper	Gulf	Comb.**	FW	850	4/70	Cotton Valley	Sandstone	16.6	200	11,700	23	4 @ 22	Prim.	90	80	25% finished	Prom.	No
Sloss	Neb.	Kimball	Amoco	Comb.††	FW	960	2/63	Muddy J	Sandstone	19.5	191	6,200	39	0.8 @ 200	WF	30	24	Terminated	Succ.	No
Red Bank	Okla.	Creek	Sun	Comb.	Pilot§	200	6/66	Dutcher	Sandstone	20	1,850	3,300	20	60 @ 120	Prim.			Terminated	Disc.	No
North Fitts	Okla.	Pontotoc	Conoco	Comb.	Pilot§	200	11/70	McAlester	Sandstone	22.4		1,700	33	6 @	WF	28		Terminated	Disc.	No
Loco	Okla.	Stephens	Conoco	Comb.	Pilot§	60	-/63	A sand	Sandstone			550	21	600 @ 70	Prim.			Terminated	Disc.	No
Casablanca, West	Tex.	Duval	Mobil	Comb.¶¶	FW	250	2/67	Cole	Sandstone	34	500	1,030	20	45 @ 100	Prim.	72	57.1	Nearing completion	Succ.	Yes
Cedro Hill	Tex.	Duval	Mobil	Comb.	FW	24	9/69	Cole "B"	Sandstone	35	600	1,450	25	35 @ 106	Prim.	64	59	Terminated	Disc.	No
Cedro Hill	Tex.	Duval	Mobil	Comb.	FW	167	12/68	Cole "C"	Sandstone	35	600	1,450	20	35 @ 106	Prim.	65	59	Terminated	Disc.	No
Charamousca	Tex.	Duval	Mobil	Comb.	FW	110	7/70	Mirando	Sandstone	32	600	1,580	20	50 @ 105	Prim.	50.8	50.4	Terminated	Fail	No
D.C.R. 79	Tex.	Duval	Mobil	Comb.	FW	450	6/70	Cole "C"	Sandstone	32.5	970	1,500	20	30 @ 107	WF	74.2	73.9	Terminated		No
Gov't Wells N	Tex.	Duval	Mobil	Comb.	FW	109	2/65	Gov't Wells	Sandstone	32	800	2,300	22	10 @ 120	Prim.	54	46	Terminated	Prom.	No
Gov't Wells N	Tex.	Duval	Mobil	Comb.	FW	198	9/62	Gov't Wells	Sandstone	32	800	2,300	22	10 @ 120	Prim.	53	46	Terminated	Prom.	No
O'Hern	Tex.	Duval	Mobil	Comb.	Pilot§	260	7/68	Cockfield	Sandstone	28	300	2,800	27.6	2.2 @ 140	WF	62	60	Terminated	Disc.	No
West Seventy Six	Tex.	Duval	Mobil	Comb.	FW	546	10/68	Cole	Sandstone	31.2	1,087	1,350	20	25 @ 96	Prim.	90	83	Half finished	Succ.	Yes
Talco	Tex.	Franklin & Titus	Exxon	Comb.	Pilot	18.6	7/72	Paluxy	Sandstone	26	2,200	4,200	22	20-25 @ 147	WF	65		No response	TETT	No
Saratoga	Tex.	Hardin	Gen'l. Crude	Comb.	FW	50	12/70	Miocene	Sandstone	32	750	900	19	85 @ 103	Prim.	58	16	20% finished	Prom.	
Hankamer	Tex.	Liberty	Gulf	Comb.	FW	112	10/69	Miocene	Sandstone	30.5	800	3,900	23.8	4.5 @ 136	Prim.	40.4	20.5	Terminated	Disc.	No
Montague Co. (Regular)	Tex.	Montague	Conoco	Comb.	Pilot§	80	2/71	Canyon	Sandstone	23	435	1,400	28		WF			Terminated	Disc.	No
Trix-Liz	Tex.	Titus	Sun	Comb.	FW	244	9/68	Woodbine	Sandstone	28	500	3,650	24	26 @ 138	Prim.	86	76	Terminated	Prom.	Yes
Kermit	Tex.	Winkler	Mobil	Comb.	Pilot§	10	8/69	Yates	Sandstone	18	29	2,900	37	7.3 @ 85	WF			Terminated	Fail	No
North Tisdale	Wyo.	Johnson	Conoco	Comb.	FW	232	-/58	Curtis	Sandstone	24.5	787	929	19.4	175 @ 70	Prim.	95-100	30-40	Terminated	Disc.	No
West Coalinga	Calif.	Fresno	Std. Ca.	SS	FW	1,200	-/66	Temblor	Sandstone	35	400	1,200	14	1.2M @ 90	Prim.	85	75	75% finished	Succ.	Yes
Coalinga	Calif.	Fresno	Shell	SS		1,320	-/66	Temblor	Sandstone	28	1,000	900-2,800	10-18	200-5.5M @ 90-100	Prim.	89		40% finished		
Cymric	Calif.	Kern	Gulf	SS	FW	80	6/66	Tar	Sandstone	32	3,000	1,000	10	10.5M @ 89	WF	100	50±	Nearing completion	Succ.	Yes
Cymric	Calif.	Kern	Mobil	SS	FW	170	7/65	Wellport	Sandstone	38	3,000	400-900	12-13	1.5M @ 95	Und.	99	75	30% finished	Succ.	Yes
Cymric	Calif.	Kern	Std. Ca.	SS	FW	700	-/66	Amnicola Tulare	Sandstone	35	4,000	1,000	13	2.4M @ 85	Prim.	90	75	Half finished	Succ.	Yes
Edison	Calif.	Kern	Exxon	SS	FW	700	6/65	Kern River	Sandstone	30	2,000	1,400	16	310 @ 95	Prim.	90	80	30% finished	Succ.	Yes
Kern Bluff	Calif.	Kern	Gulf	SS	FW	300	4/65	Chanac	Sandstone	31	2,000	900-1,030	16	8M @ 95	Prim.	80	50±	Nearing completion	Succ.	Yes
Kern Front	Calif.	Kern	ARCO	SS	FW	160	11/64	Plio-Chanac	Sandstone	32	1,600	2,500	13.7	400 @ 120	Prim.			Half finished	Succ.	Yes
Kern Front	Calif.	Kern	Std. Ca.	SS	FW	640	-/70	Chanac	Sandstone	27	700	2,400	12	3M @ 110	Prim.	80	75	Half finished	Succ.	Yes
Kern River	Calif.	Kern	Chanslor	SS	FW	65	5/67	Kern R.	Sandstone	30	1,000	400	13.8	928 @ 140	Prim.	95	90.2	70% finished	Succ.	Yes
Kern River	Calif.	Kern	Chanslor	SS	FW	80	6/64	400 ft	Sandstone	33	3,000	1,000	13.8	928 @ 140	Prim.	87.5	78.6	67% finished	Succ.	Yes
Kern River	Calif.	Kern	Chanslor	SS	FW	115	6/66	300 ft	Sandstone	33	2,000	800	13.8	928 @ 140	Prim.	89.5	80	90% finished	Succ.	Yes
Kern River	Calif.	Kern	Getty	SS‡‡	FW	5,000	-/62	Kern R.	Unconsolidated	38.4	4,070		14	11M @ 100	Prim.			35% finished	Succ.	Yes
Kern River	Calif.	Kern	Std. Ca.	SS	FW	1,400	-/66	Kern R.	Sandstone	34	4,000	1,000	14	4M @ 85	Prim.	85	78	75% finished	Succ.	Yes
Kern River	Calif.	Kern	Shell	SS		1,300	4/63	Kern R.	Sandstone	31	2,000	300-1,300	11-13	3M @ 85	Prim.	90		Half finished	Succ.	Yes
Lost Hills	Calif.	Kern	ARCO	SS	FW	15	6/67	Plio-Etchegoin	Sandstone	32		500	12.5	1M @ 100				Half finished	Succ.	Yes
Lost Hills, Section 18	Calif.	Kern	Gulf	SS	FW	120	8/64	Tar	Sandstone	41	1,000	200-400	16	3M @ 85		100	50±	Nearing completion	Succ.	Yes
Midway Sunset	Calif.	Kern	Mobil	SS	FW	350	10/70	Monarch	Sandstone	34	4,000	950	13.5	800 @ 85	Prim.	97	94	25% finished	...	...
Midway Sunset	Calif.	Kern	Mobil	SS	FW	350	11/67	Potter	Sandstone	36	1,000	1,000	13	1M @ 100	Prim.	88	75	Half finished	...	...
Midway Sunset	Calif.	Kern	Shell	SS		565	1/64	Tulare, Potter, Upper Miocene	Sandstone	38	2,000	600-1,500	10-14	2.4-5.0M @ 80-100	Prim.	95		30% finished	Succ.	Yes
McKittrick	Calif.	Kern	Occidental	SS	FW	45	4/65	Orig. sand	Sandstone	37		900	14		Prim.	?	?	Half finished	Succ.	Yes

*Source: Reprint from OGJ article of March 25, 1974, entitled "Journal Survey Shows Recovery Projects Up".

**Sophisticated is defined by W.B.Bleakley, OGJ Production Editor as enhanced oil recovery methods more complex than conventional waterflooding.

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FIGURE III-4 (continued)

OIL AND GAS JOURNAL* SURVEY OF CURRENTLY OPERATING AND RECENTLY ABANDONED SOPHISTICATED** OIL RECOVERY PROJECTS

Field	State	County	Oper.	Type project*	Pilot or field-wide (FW)	Project area, acres	Start date	Pay zone	Type	Porosity, %	Permeability, md	Depth, ft	Reservoir oil °API	Reservoir oil cp @ °F	Prev. prod. by†	Res. oil sat'n at start, %	Est. resid. oil sat'n at end, %	Project's maturity	Project's status‡	Profitable?
McKittrick	Calif	Kern	Std. Ca.	SS	FW	120	-/71	Tulare	Sandstone	35	2,000	870	15	4M @ 100	Prim	98	75	Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	ARCO	SS	PP	1,000	9/63-6/66	Pico Etchegoin M-: Potter	Sandstone	30	1,000-3,000	1,000-2,500	12-17	2'0 20M @ 100	P...			Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	Chanslor	SS	FW	980	3/64	Potter 250	Sandstone	35	3,500	1,500	12	283 @ 140	Prim.	97	70	50% finished	Succ.	Yes
Midway Sunset	Calif.	Kern	Chanslor	SS	FW	600	6/64	Spellacy 300 ft	Sandstone	33	2,000	1,500	11		Prim.	95	85	Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	McCulloch	SS	FW	60	-/65	Potter	Sandstone	25	2,000	1,100	12	5M @ 80	Prim.	75	40	Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	Occidental	SS	FW	23	9/64	Monarch	Sandstone	33	2,400	1,080	12.6		Prim.	?	?	Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	Occidental	SS	FW	48	6/64	Potter	Sandstone	38	1,566	1,700	11.5	283 @ 140	Prim	?	?	Half finished	Succ.	Yes
Midway Sunset	Calif.	Kern	Std Ca	SS	FW	160	-/66	Potter	Sandstone	36	1,300	1,200	14	1.1M @ 100	Prim	[illegible]	70	Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	Std Ca	SS	FW	700	-/66	Sub Lakeview	Sandstone	34	2,000	1,500	14	1M @ 100	Prim.	88	80	Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	Std Ca	SS	FW	95	-/67	Oig	Sandstone	32	1,000	2,400	15	177 @ 122	Prim.	[illegible]	80	Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	Std Ca	SS	FW	900	-/66	Top Oil	Sandstone	32	400	1,400	16	800 @ 100	Prim.	80	70	Half finished	Succ.	Yes
Midway Sunset	Calif	Kern	Sun	SS	FW	80	3/64	Potter	Sandstone	34	2,300	1,700	12	8M @	BHN	64	51	Half finished	Succ.	Yes
Poso Creek	Calif	Kern	Std. Ca.	SS	FW	240	-/70	Chanac	Sandstone	28	1,500	2,500	14	1M @ 120	Prim.	90	80	Half finished	Succ.	Yes
Santiago	Calif.	Kern	Gulf	SS	FW	80	4/66	Tar	Sandstone	34	3,000	550-1,250	14	4.8M @ 92	Prim.	85	50±	Half finished	Succ.	Yes
S. Belridge	Calif.	Kern	Std. Ca.	SS	FW	150	-/66	Tulare	Sandstone	37	2,000	870	13	1.3M @ 90	Prim.	85	80	75% finished	Succ.	Yes
Brea-Olinda	Calif	Orange	Chanslor	SS	FW	10	6/69	Second	Sandstone	30	1,800	1,200	12		Prim.	100	80	15% finished	Succ.	Yes
Brea-Olinda	Calif.	Orange	Chanslor	SS	FW	40	6/69	First	Sandstone	30	2,000	800	12	283 @ 140	Prim.	90	80	80% finished	Succ	Yes
Huntington Beach	Calif	Orange	Signal	SS	FW	6,700	-/64	Ta	Sandstone	31		2,000	14	1.2 @ 100	Prim.	60	40	Half finished	Succ.	Yes
Yorba Linda	Calif	Orange	Gulf	SS	FW	80	10/62	[illegible]	Sandstone	31	6,000	235-1,900	12	12M @ 90	Prim	90	50±	Nearing completion	Succ	Yes
Yorba Linda	Calif	Orange	Shell	SS		180	3/61	Upper Congl	Sandstone	25	600	400-830	12	6,400 @ 85	Prim.	96		60% finished	Succ	Yes
Cat Canyon	Calif.	Santa Barbara	Conoco	SS	FW	650	-/63	Sisquoc	Sandstone	33	1,200	3,000	10	1.3M @ 130	Prim.	95-100	80	20% finished	Succ	Yes
Smackover	Ark.	Union & Ouachita	Phillips	SD	FW	985	5/71	Nacatoch	Sandstone	36	5,000	2,000	20	75 @ 110	Prim			20% finished	Prom.	
Smackover	Ark.	Union	Gulf	SD	Pilot¶	80	6/69	Nacatoch	Sandstone	33	500	2,000	20	74 @ 110	Prim	55	40	Terminated	Succ.	No
W. Coalinga	Calif.	Fresno	Std. Ca.	SD	Pilot¶	30	-/73	Temblor	Sandstone	35	400	1,200	14	1.2M @ 90	SS	80	50	Just started	TETT	?
Kern River	Calif.	Kern	Chanslor	SD	Pilot¶	10	7/68	Kern R	Sandstone	33	1,000	400	13	198 @ 140	Prim.	95	70	35% finished	Prom.	Yes
Kern River	Calif.	Kern	Chanslor	SD	Pilot¶	15	6/69	Kern R	Sandstone	33	3,000	1,000	13.8	928 @ 140	SS	81.7	69.6	Just started	Prom.	No
Kern River	Calif.	Kern	Std. Ca.	SD	FW	150	-/68	Kern R	Sandstone	34	4,000	1,000	14	4M @ 85	SS	80	50	Just started	Succ.	Yes
Midway Sunset	Calif.	Kern	ARCO	SD	Pilot	6	6/69	Potter	Sandstone	30	1,000-3,000	1,000-2,500	12-17	[illegible] 2M @ 100	SS			Just started	TETT	
Midway Sunset	Calif.	Kern	Shell	SD		80	8/71	Potter	Sandstone	32	2,000	1,200	11	5M @ 90	SS	91		25% finished	Succ.	Yes
Midway Sunset	Calif.	Kern	Chanslor	SD	FW	80	1/67	Potter 120'	Sandstone	35	3,500	1,500	12	283 @ 140	SS	95	60	40% finished	Succ.	Yes
Midway Sunset	Calif.	Kern	Chanslor	SD	Pilot¶	50	3/68	Potter 120'	Sandstone	35	3,500	1,500	12		SS	93	60		Prom	No
Midway Sunset	Calif	Kern	Chanslor	SD	Pilot	20	9/73	Spellacy-160 ft	Sandstone	30	2,000	1,000	11	480 @ 140	SS	94	70		TETT	No
Mount Poso	Calif.	Kern	Shell	SD	Pilot	280	10/71	Upper Vedder	Sandstone	33	20,000	1,800	16	280 @ 110	Prim.	65		20% finished	Succ.	Yes
S. Belridge	Calif.	Kern	McCulloch	SD	FW	100	-/70	Tulare	Sandstone	25	1,000	800	12		Prim.	60	40	Just started	Prom	No
Santiago	Calif.	Kern	Texaco	SD	Pilot¶	10	-/72	Tulare	Sandstone	39	1,500	1,200	12	4M @ 100	Prim			Just started	Prom.	Yes
San Ardo	Calif.	Monterey	Mobil	SD¶¶	FW	2,900	6/63	Lombardi Aurignac	Sandstone	35	7,750	2,300	11.3	3.1M @ 125	Prim.	86	63	20% finished		
San Ardo	Calif.	Monterey	Texaco	SD	Pilot¶	80	-/69	Lombardi	Sandstone	33	8,000	1,900	11	11M @ 100	SS	...	...	Half finished	Prom.	Yes
San Ardo	Calif.	Monterey	Texaco	SD	FW	1,725±	-/65	Aurignac	Sandstone	39	1,500	2,200	13	4.5M @ 100	SS			Just started	Succ.	Yes
Brea-Olinda	Calif.	Orange	Chanslor	SD	Pilot¶	10	3/73	First	Sandstone	30	2,000	800	12	283 @ 140	SS	85	70	Just started	Prom.	
Huntington Beach	Calif.	Orange	Std. Ca.	SD	FW	300	4/65	Tar Zone	Sandstone	34	2,000	2,000	12.7	2M @ 140	Prim.	88	50	10% finished	Succ	Yes
Cat Canyon	Calif.	Santa Barbara	Conoco	SD	Pilot	5	-/71	Sisquoc	Sandstone	33	1,200	2,800	10	1.3M @ 130	Prim.	95-100		Nearing completion	TETT	No
Slocum	Tex.	Anderson	Texaco	SD	Pilot	18	8/70	Carrizo	Sandstone	32	1,250	580	19	1.8M @ 82	NP	...		Half finished	NE	No
Winkleman Dome	Wyo	Fremont	Amoco	SD	FW	100	3/64	Nugget	Sandstone	25	638	1,220	14	900 @ 81	Prim.	75	25	50% finished	Succ	Yes
Wilmington	Calif.	Los Angeles	Mobil	Poly	FW	440	7/69	Ranger	Sandstone	33	2,300	2,750	15	76 @ 130	WF	78	74	Terminated		No
Big Sinking Field	Ky.	Lee	Ashland	Poly	Pilot¶	3	12/73	Corniferous	Sandstone	22	30-50	1,000	38	10 @ 60	WF	65		Just started	TETT	
Vacuum	N.M.	Lea	Mobil	Poly	Pilot§	400	11/65	San Andres	Dolomite	10.6	21	4,700	37	1.5 @ 100	WF			Terminated	Disc.	No
Sho-Vel-Tum (Tatums)	Okla.	Carter	Mobil	Poly.	Pilot§	70	11/68	Deese	Sandstone	22.3	860	2,500	26	68 @ 83	WF	64	60	Terminated	Disc.	
Stroud	Okla.	Lincoln	Sun	Poly	Pilot§	600	8/70	Prue	Sandstone	18	25	2,900	44	2 @ 103	WF			Terminated	Disc.	No
Naval Reserve	Okla.	Osage	Texaco	Poly	Pilot	83	8/69	Burbank	Sandstone	17	40	2,650	39.6	2.6 @ 100	WF			Terminated	TETT	No
Sand Hills Tubb	Tex	Crane	Mobil	Poly.	FW	1,440	7/69	Tubb	Dolomite	10	15	4,300	35	1.5 @ 90	WF	...		Half finished	NE	
Brelum	Tex.	Duval	Texaco	Poly.	FW	427	4/69	Gov't Wells	Sandstone	29	399	1,950	23	12 @ 115	WF	50		Just started	Succ	Yes
Magist Ranch	Tex	Duval	Texaco	Poly.	FW	145	4/73	First Argo	Sandstone	31	342	1,900	20	10 @ 115	WF	45		Just started	TETT	
O'Hern	Tex.	Duval	Mobil	Poly.	Pilot§	1,067	11/67	Cochfield	Sandstone	28	300	2,800	27.6	2.2 @ 140	WF	68	60	Terminated	Disc.	Yes
S. Seventy Six	Tex.	Duval	Mobil	Poly.	Pilot§	52	9/69	Cole		34	850	920	20	50 @ 98	WF	81		Terminated	Disc.	No
W. Seventy Six	Tex	Duval	Texaco	Poly.	Pilot¶	91	11/72	Cole	Sandstone	30	1,200	1,350	20	12 @ 100	Prim.	54		Half finished	Succ.	Yes
Howard-Glasscock	Tex	Howard	Sun	Poly.	Pilot§	10	8/70	Yates	Sandstone	18	75	1,400	27	11 @ 93	WF	34	33	Terminated	Prom.	No
Stephens County Regular	Tex.	Stephens	Mobil	Poly.	FW	2,280	2/73	Caddo Reef	Limestone	14.5	12	3,200	40	2.3 @ 70	WF	...	...	Just started	Succ.	Yes
McCamey	Tex.	Upton	Tex. Pacific	Poly.	Pilot¶	20	2/72	Grayburg San Andres	Limestone	8.5	2.5	2,200	26	28 @ 80	Prim.	81	71	Just started	TETT	No
Volpe	Tex	Webb	Mobil	Poly.	FW	245	10/66	Lopez	Sandstone	30	300	2,400	31	5 @ 124	Prim.	45	26	Terminated	Disc.	No
Keystone	Tex.	Winkler	Mobil	Poly.	Pilot§	320	1/69	Colby	Sandstone & Limestone	12	5	3,100	38	2 @ 86	WF	...	...	Terminated	Disc.	No
Stewart Unit	Wyo.	Campbell	NCRA	Poly.	FW	2,680	5/72	Minnelusa	Sandstone	16.3	92	8,100	21.5	24.2 @ 136	Prim.	74	...	Half finished	Prom.	Yes
[illegible] Creek	Wyo.	Johnson	Texaco	Poly.	Pilot§	320	10/72	Shannon Sand	Sandstone	22	120	2,000	36	3 @ 86	WF	70	60.7	Terminated	Disc.	No
Shell Creek	Wyo.	Weston	Fina	Poly.	FW	740	9/67	Newcastle	Sandstone	14.6	70.4	3,300	37	3.21 @ 124	WF	82	73	Nearing completion	Succ.	Yes

*Source: Reprint from OGJ article of March 25, 1974, entitled "Journal Survey Shows Recovery Projects Up".

**Sophisticated is defined by W.B.Bleakley, OGJ Production Editor as enhanced oil recovery methods more complex than conventional waterflooding.

FIGURE III-4 (continued)

OIL AND GAS JOURNAL* SURVEY OF CURRENTLY OPERATING AND RECENTLY ABANDONED SOPHISTICATED** OIL RECOVERY PROJECTS

Field	State	County	Oper.	Type project*	Pilot or field-wide (FW)	Project area, acres	Start date	Pay zone	Type	Porosity, %	Permeability, md	Depth, ft	— Reservoir oil —		[illegible]†	Resid. oil sat'n at start, %	Est. resid. oil sat'n at end, %	Project's maturity	Project's status‡	Profitable?
													°API	cp @ °F						
Greeley Olcese	Calif.	Kern	Mobil	MH	FW	550	8/64	Olcese	Sandstone	20	18	10,600	35	0.4 @ 244	Prim.	82	56	Nearing completion		
Midway Sunset	Calif.	Kern	Std Ca.	MH	FW	530	-/57	Exeter	Sandstone	24	400	5,200	31	1 @ 180	Prim.	82	52	Terminated	Succ.	Yes
Midway Sunset	Calif.	Kern	Std Ca.	MH	FW	185	-/63	Monarch	Sandstone	25	410	4,700	32	1 @ 175	Prim.	97	73	Nearing completion	Succ.	Yes
N. Coles Levee	Calif.	Kern	ARCO	MH§§	PP	624	8/67	Stevens W 31 S & 21 1	Sandstone	21	95	9,500	36	0.41 @ 235	GI		59	Terminated	Prom.	?
Ventura	Calif.	Ventura	Shell	MH§§		325	1/66	[illegible]	Sandstone	17	20	10,000	30	0.9 @ 215	Prim.	70		60% finished	Succ.	Yes
Short Junction	Okla.	Cleveland	Conoco	MH	Pilot§		-/57	Hunton	Limestone	5.8	0.77	8,100	35		Prim.			Terminated	Disc.	No
Fairway	Tex.	Anderson & Henderson	Hunt	MH	FW	22,600	3/66	James Lime	Limestone			9,900	48	0.15 @ 265	Prim.	73	33	50% finished	Succ.	Yes
Midland Farms	Tex.	Andrews	Amoco	MH	FW	4,000	5/60	Wolfcamp	Limestone	12.2	6-600	8,360	41	0.324 @ 160	Prim.	93	46	Terminated	Disc.	Yes
University Block 31	Tex.	Crane	ARCO	MH	FW	7,000	6/49	Devonian	Dolomite	15	1.0	8,400	46	0.30 @ 139	Prim.	98.6	34.6	70% finished	Succ.	Yes
University Waddell	Tex.	Crane	Mobil	MH	FW	1,200	11/67	Devonian	Dolomite	10.7	3	9,000	43	0.5 @ 140	Prim.			Half finished	Succ.	Yes
Levelland	Tex.	Hockley	Amoco	MH	Pilot§	12	3/73	San Andres	Dolomite	11.5	3.5	4,800	30	2 @ 105	Prim.	84	32	Just started	TETT	No
Levelland	Tex.	Hockley	Amoco	MH	FW	1,200	5/71	San Andres	Dolomite	10.2	1.9	4,800	30	2 @ 105	Prim.	84	20	Just started	TETT	No
Slaughter	Tex.	Hockley	Amoco	MH	Pilot§	12	4/72	San Andres	Dolomite	11	3.8	4,950	32	1.4 @ 105	Prim.	84	32	Just started	TETT	No
West Ranch	Tex.	Jackson	Mobil	MH	Pilot¶	480	11/64	Glasscock	Sandstone	29.4	394	5,500	31	0.8 @ 168	Prim.			75% finished	Succ.	Yes
Salt Creek	Tex.	Kent	Gen'l Crude	MH	Pilot¶	200	4/69	Canyon Reef	Limestone	12.5	10.5	6,300	40	0.8 @ 129	WF	50	35	Half finished	Prom.	?
Clayton	Tex.	Live Oak	Mobil	MH	FW	1,145	3/65	Queen City-B	Sandstone	26.9	98	5,050	41	0.52 @ 190	Prim.	37.4	21.9	Terminated	Succ.	Yes
Parks Pennsylvanian	Tex.	Midland	Mobil	MH	FW	7,145	6/57	Penn Bend	Limestone	6.7	2.6	10,500	45	0.5 @ 170	Prim.			Nearing completion	Succ.	Yes
Pegasus	Tex.	Midland	Mobil	MH	FW	880	12/68	San Andres	Sandstone	19	18	5,800	31	4.2 @ 107	Prim.			Half finished	Succ.	Yes
Wichita Co. Regular	Tex.	Wichita	Mobil	MH	Pilot§	20	5/61-7/62	Gunsight Sand	Sandstone	22	53	1,750	42	2.2 @ 96	WF			Terminated	Disc.	No
Meadow Creek	Wyo.	Johnson	Conoco	MH	FW	442	-/57	Lakota "B"	Sandstone	11.8	32	7,000	40	0.6 @ 180	Prim.	65-70	50-55	Terminated	Disc.	Yes
Bridger Lake	Wyo. & Utah	Uinta & Summit	Phillips	MH	FW	3,800	4/70	Dakota	Sandstone	12.8	79	15,600	40	0.53 @ 225	Prim.			15% finished	Succ.	Yes
McCallum Unit	Colo.	Jackson	Conoco	MC	FW	601	12/73	Pierre "B"	Sandstone	19.5	59	1,250	28	10 @ 70	Prim.	95-100		Just started	TETT	
Little Creek	Miss.	Lincoln & Pike	Shell	MC	Pilot*	40	2/74	Tuscaloosa	Sandstone	23	90	10,350	39	0.4 @ 248	WF	51		Just started	TETT	
North Cowden	Tex.	Ector & Andrews	Amoco	MC	Pilot¶	12	6/73	Grayburg	Dolomite	9.3	5.6	4,300	34	1.4 @ 94	Prim.	74	31	Just started	TETT	No
Crossett	Tex.	Crane & Upton	Shell	MC	FW	1,700	5/72	Devonian	Limestone	22	5	5,300	44	0.36 @ 106	GI	86		Just started	TETT	
S. Gillock	Tex.	Galveston	Amoco	MC	FW	5,900	2/72	Frio	Sandstone	27.5	900	9,000	39	0.35 @ 214		100	15	20% finished	TETT	Yes
Slaughter	Tex.	Hockley	Amoco	MC	Pilot¶	4,950	12/72	San Andres	Dolomite	11.8	9.1	4,950	32	1.4 @ 105	Prim.	84	36	Just started	TETT	No
Kelly Snyder	Tex.	Scurry	Chevron	MC	FW	57,000	1/72	Canyon	Limestone	7.6	19.4	6,900	43	0.35 @ 130	WF	80	48	Just started	TETT	?
Wasson	Tex.	Yoakum	ARCO	MC	Pilot*	320	11/72	San Andres	Dolomite	11	2	5,100	32	0.97 @ 107	Prim.	85.4		Just started	TETT	No
North Meadow Creek	Wyo.	Johnson	Conoco	MC	Pilot§	40	-/63	Sussex	Sandstone	20.7	20	3,500	40	1 @ 106	WF	75	75	Terminated	Disc.	No
Clear Creek	N.D.	McKenzie	Skelly	MH	FW	3,120	2/64	Madison Mission Canyon	Limestone	14.9	1	9,200	44	0.13 @ 246	Prim.	73	23	80% finished	Succ.	Yes
Anse La Butte	La.	St. Martin	Amoco	MF	FW	22	4/73	Patin	Sandstone	30	1,030	4,200	37	0.7 @ 175	?	100	21	Just started	Prom.	
Robinson	Ill.	Crawford	Marathon	MSF	Expanded	40	9/68	Robinson Sd	Sandstone	20	200	1,000	35-36	7 @ 60	WF	35-45		Nearing completion		
Benton	Ill.	Franklin	Shell	MSF	Pilot	160	11/72	Tar Springs	Sandstone	19	165	2,100	38	3.5 @ 86	WF	55		Just started	TETT	
Bridgeport	Ill.	Lawrence	Marathon	MSF	Pilot	2.5	9/69	Kirkwood Sd	Sandstone	18	90	1,500	38-39	5.5 @ 72	WF	30-45		Terminated		
Bradford	Penn.	McKean	Pennzoil	MSF	Pilot¶	46	3/71	Bradford	Sandstone	22	100	1,900	45	4 @ 71	WF	40	20	40% finished	Succ.	No
Goodwill Hill	Penn.	Warren	Quaker State	MSF	Pilot	10		Venango 1st	Sandstone			600	40	4.5 @ 55	GI			Half finished	TETT	
Higgs Unit	Tex.	Jones	Union	SOF	Pilot§	8.23	7/69	Bluff Crk.	Sandstone	22.9	500	1,870	37	4.1 @ 95	WF	35	?	Terminated	Prom.	No
E. Velma (Middle Block)	Okla.	Carter-Stephens	Amoco	WFAG	Pilot¶	50	12/73	Sims	Sandstone	16	67	5,500	10	2 @ 106	GI	70	45	Just started	TETT	
Winkleman Dome	Wyo.	Fremont	Amoco	WFAG	FW	752	5/70	Tensleep	Sandstone	15	106	3,300	25	11 @ 125	WF	78	59	30% finished	NE	Yes
Little Buffalo Basin	Wyo.	Park	Amoco	WFAG	FW	2,300	-/66	Embar	Dolomite	18	44	4,500	20	32 @ 122	Prim.	92	73	30% finished	Succ.	Yes
Little Buffalo Basin	Wyo.	Park	Amoco	WFAG	FW	1,500	-/59	Tensleep	Sandstone	14	90	1,500	20	42 @ 128	Prim.	33	10	40% finished	Succ.	Yes
N.E. Butterly	Okla.	Garvin	Conoco	HWF	Pilot§	160	6/70	Oil Creek	Sandstone	20		4,100	13.6	[illegible] @ 100	Prim.			Terminated	Disc.	No
Lora	Okla.	Stephens	Conoco	HWF	Pilot§	2.5	-/61	A sand	Sandstone	25.6	2,500	525	21	600 @ 70	Prim.			Terminated	Disc.	No
Wichita Co. Regular	Tex.	Wichita	Mobil	LTWF	Pilot	200	11/73	Gunsight	Sandstone	22	53	1,750	42	2.2 @ 96	WF			Just started	TETT	
Griffin Consolidated	Ind.	Gibson	Conoco	SF	Pilot	0.8	11/73	Upper Cypress	Sandstone	20	75	2,400	37		WF			Just started	TETT	
Sayles	Tex.	Jones	Conoco	SF	Pilot§	2.5	-/63	Flippen	Sandstone	21.7	457	1,900	38		WF	30	30	Terminated	Disc.	No
Montague Co. Reg.	Tex.	Montague	Conoco	SF	Pilot§	2.5	-/63	Cisco	Sandstone	24.2	394	1,200	27		Prim.	50	50	Terminated	Disc.	No
Big Muddy	Wyo.	Converse	Conoco	SF	Pilot	5	-/73	2nd Wall Creek	Sandstone	19.2	39	3,100	34	5.6 @ 114	WF	85		Just started	TETT	
West Perryton	Tex.	Ochiltree	Sun	CSF	FW	1,070	6/72	8,100 ft Morrow	Sandstone	13	19	8,100	38	0.8 @ 168	Prim.	17	59	25% finished	TETT	?
North Ward Estes	Tex.	Ward	Gulf	CSF	Pilot*	40	7/73	Queen	Sandstone	22	25	3,100	36	2.3 @ 83	WF	76	48	Just started	TETT	No
Harper Field	Tex.	Ector	Cities	GI	FW	4,256	2/68	Devonian	Dolomite	8.8	1	10,100	42.8	0.356 @ 60	Prim.	56.6	81.3	75% finished	Disc.	Yes
Spraberry Trend	Tex.	Midland	Mobil	GP	Pilot§	160	2/70	Spraberry	Siltstone	12	0.2	7,200	36	1.2 @ 140	WF			Terminated	Disc.	No

*Comb.=In situ combustion; SS=Steam soak; SD=Steam drive; Poly.=Polymer flood; MH=Miscible (hydrocarbon); MC=Miscible (carbon dioxide); MSF=Micellar solution flood; SOF=soluble oil flood; WFAG=Waterflood, alternating gas; HWF=Hot waterflood; LTWF=Low-tension waterflood; SF=Surfactant flood; CSF=caustic soda flood; GI=Gas injection; GP=Gas pulsing. †Prim.=Primary; SS=Steam soak; NR=Nonreservoir; WF=waterflood; NP=Nonproductive; Und.=Undeveloped; BHH=Bottom-hole heater; GI=Gas injection. ‡Suc.=Successful; Dis.=Discouraging; Prom.=Promising; TETT=Too early to tell; Fail=Failure; NE=Not evaluated. ¶Expansion likely. §Expansion unlikely. ‖Plus steamsoak and steam drive. **Combustion-line gas drive. ††Plus steam drive. ‡‡Plus combustion and steam soak. §§Combined miscible hydrocarbon and waterflood. *Now injecting water.

*Source: Reprint from OGJ article of March 25, 1974, entitled "Journal Survey Shows Recovery Projects Up".

**Sophisticated is defined by W.B.Bleakley, OGJ Production Editor as enhanced oil recovery methods more complex than conventional waterflooding.

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FIGURE III-5

OIL AND GAS JOURNAL* SURVEY OF PLANNED NEW SOPHISTICATED** OIL RECOVERY PROJECTS

Field	State	Company	Type project*	Pilot or fieldwide (FW)	Project acres	Pay zone	Depth ft	Crude °API	Target date for start
Kern River	Calif.	Chanslor	Comb	Pilot	10	60 ft	320	14	1974
Tejon	Calif.	Chanslor	Comb	Pilot	20	70 ft	2,650	16	1975
Carlyle	Kan.	Layton	Comb	Pilot	20	B'ville			
Bellevue	La.	Cities	Comb	Pilot†	10	Nacatoch	400	19	1974
Shoreline	La.	Kirby	Comb	Pilot‡	60	Nacatoch	1,050	22	1973
Heidelberg	Miss.	Gulf	Comb	Pilot	160	Christmas	5,100	20	1974
Kern River	Calif.	Getty	SS SD	FW¶	450	Kern River	1,000	14	1974
Kern River	Calif.	Getty	SS SD	FW¶	600	Kern River	1,000	14	1975
Kern River	Calif.	Getty	SS SD	FW¶	600	Kern River	1,000	14	1976
Kern River	Calif.	Getty	SS SD	FW¶	600	Kern River	1,000	14	1977
Kern River	Calif.	Getty	SS SD	FW¶	600	Kern River	1,000	14	1978
Kern River	Calif.	Getty	SS SD	FW¶	250	Kern River	1,000	14	1979
Cymric	Calif.	Chanslor	SD	Pilot	10	60 ft	1,500	12	1974
Cymric	Calif.	Std. of Cal.	SD	Pilot	60	Tulare	1,000	13	1974
Kern River	Calif.	Chanslor	SD	FW	298	300 ft	600	13	1975
Midway-Sunset	Calif.	Chanslor	SD	Pilot	10	100 ft	800	11	1974
Midway-Sunset	Calif.	Chanslor	SD	Pilot	10	60 ft	800	11	1974
Midway-Sunset	Calif.	Std. of Cal.	SD	Pilot	15	Monarch	1,000	13	1974
N.E. McKittrick	Calif.	Std. of Cal.	SD	FW	60	Ammicola	1,100	11	1974
W. Coalinga	Calif.	Std. of Cal.	SD	FW	640	Temblor	1,000	13	1974
Caddo Pine Island	La.	Texaco	SD	Pilot	30	Nacatoch	—900	19	1975
Port Barre	La.	Texaco	SD	FW	60	1,500 ft	—1,450	19	1974
Poncho	Colo.	Midwest	Poly.	FW	640	"J" sand	6,000	40	1975
Stephens	Texas	Tex.-Pacific	Poly.	Pilot	5	Caddo	3,100	38	1975
Bone Pile	Wyo.	Midwest	Poly.	FW	1,760	Minl "A"	10,800	32	1974
Skull Creek Unit	Wyo.	Texaco	Poly.	FW	920	Newcastle	2,450	32-35	1974
N. Burbank	Okla.	Phillips	MSF	Pilot	....	B'ville	....	..	
S. Okla.	Okla.	Skelly	MSF	Pilot	20	Sims	7,200	28	1974
Bradford	Pa.	Pennzoil	MSF	FW	>100	....	1,900	45	1974
Seeligson Ut.	Texas	Sun	MSF	FW	1,600	13A	4,900	38	1974
LaBarge Unit	Wyo.	Texaco	MSF	Pilot	1.8	Almy	1,000	38	1974
Tinsley	Miss.	Pennzoil	FG	FW	>400		4,600	32	1974
Consolidated	Ill.	Texaco	SOF	Pilot	5	Benoist	1,800	39.5	1974
Charlson North Unit	N.D.	Texaco	W&GI	FW	9,100	Madison	8,500	42	1974
Dugout Creek Unit	Wyo.	Texaco	W&GP	Pilot	20	Shannon	2,800	36	1974

*Comb.=Combustion; SS=Steam soak; SD=Steam drive; Poly.=Polymer flood; MSF=Micellar solution flood; FG=Flue gas; SOF=Soluble oil flood; W&GI=Water and gas injection; W&GP=Water and gas pulsing. †Expansion of 10 acres. ‡Expanded 1973. ¶Scheduled expansions into new areas of the field.

*Source: Reprint from OGJ article of March 25, 1974, entitled "Journal Survey Shows Recovery Projects Up".

**Sophisticated is defined by W.B.Bleakley, OGJ Production Editor as enhanced oil recovery methods more complex than conventional waterflooding.

If neither a quoted or estimated value of OOIP existed, then RROIP was listed as zero.

Occasionally, negative numbers will be encounted in the RROIP column. For some fields, we were able to disaggregate the field into major producing formations. In these cases, we had estimates of the original oil-in-place by formation, but cumulative production only for the entire field. This situation is indicated by an "s" in the cumulative production column. In such situation, the program assumes that all the production came out of the first formation listed, sometimes resulting in a negative remaining oil in place. The actual estimate of remaining oil in place is the sum of this number plus the remaining oil in place for the other formations listed in this field.

Partitioning the Data Base: Recovery-Specific Applicability Matched to Field-Specific Characteristics

The Classification Process

The purpose of this task was to take the aggregate volume of OOIP and RROIP represented by all the fields contained in the sample and partition these volumes into smaller classifications described by user specified ranges of selected characteristics. The motivation for this partitioning was to obtain estimates of the total volumes of oil which might be suitable matched to specific recovery techniques. The "appropriateness" of certain recovery methods to each partitioned volume depends upon how loosely defined the user specified value ranges of characteristics selected to describe the partition are. The more restrictively defined the range and the greater the number of characteristics used to describe the partition, the less likely we are to find "overlaps in suitability" to alternative recovery methods for a single partition. The more loosely defined the partitioning criteria are, the larger the extent of these overlaps becomes.

To illustrate this partitioning process, Figure III-6 displays an overall breakdown of the data in terms of our best estimate of original oil-in-place and remaining oil-in-place. The data represents 349 fields with 57 billion barrels of known production, about 60% of all the oil that has been produced in this country. The known OGJ recoverable reserves in this data represent about 33 billion barrels, or about three-fourths of API's current estimate of domestic recoverable reserves. We were able to obtain in the literature original oil-in-place estimates of 105 billion barrels. Our "Estimate I" process described earlier, of estimating original oil-in-place by inflating ultimate recovery by regional factors resulted in 285 billion barrels in place. This volume is 63% of API's estimate of total already-discovered original oil in place for the United States of 450 billion barrels. Our best estimate of remaining oil-in-place is 210 billion barrels, which is about 60% of the API estimate of the already discovered remaining domestic oil in place.

In short, then, our sample of 349 large fields represents roughly 60% to 75% of all domestic oil. This is a rather impressive showing for the large fields in view of the fact that there have been some 60,000 reservoirs discovered in the United States.

The breakdown by API gravity, permeability, and depth is also shown in Figure III-6. The data indicate that a surprising amount of relatively high API gravity oil remains in the ground. According to our data, there exist 101 billion barrels of API 30° or above oil in major reservoirs. It should be noted that the large deposits of heavy oil in relatively tight sands in southern Missouri and northeastern Kansas, rated at from 5° to 50°, are not reflected in our sample.[23] The sample does contain some 63 billion barrels of oil in the 15° to 30° API range as well as 36 billion barrels for which gravity data was not obtained.

FIGURE III - 6

PARTITIONING OF ORIGINAL AND REMAINING OIL-IN-PLACE CATEGORIZATION BY SELECTED RESERVOIR CHARACTERISTICS

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                              SUMMARY INFORMATION

TOTAL NO OF FIELDS IN DATA=        349
TOTAL KNOWN CUMULATIVE PRODUCTION=      57514
TOTAL API RESERVES IN DATA      32660
TOTAL ORIG OIL IN PLACE BY DATA=    104938
TOTAL ORIG OIL IN PLACE BY EST.=    285640
BEST EST. OF REMAINING OIL IN PLACE=    210621


NO OF FIELDS FOR WHICH DISCOVERY DATE KNOWN=        321
AVERAGE DISCOVERY DATE OF THESE FIELDS=      1934
AVERAGE DATE WEIGHTED BY ORIG OIL IN PLACE=      1931
AVERAGE DATE WEIGHTED BY REMAINING OIL= 1.93253E+03


NO OF FIELDS FOR WHICH PRIMARY DRIVE KNOWN=        184
                                       GAS                COMBINATION          WATER
NO OF FIELDS                           107                    33                  43
ORIGINAL OIL IN PLACE                80703                 19069               25328
REMAINING OIL IN PLACE               62649                 14024               15943


                                 BREAKDOWN BY API GRAVITY
                  ORIGINAL OIL IN PLACE          REMAINING OIL IN PLACE
LS TH 15                 10337                           8497
15 TO 20                 28678                          23445
20 TO 25                 16912                          12919
25 TO 30                 35721                          28074
30 TO 35                 49401                          36285
35 TO 40                 62956                          44709
GR TH 40                 26553                          19951
UNKNOWN                  37584                          36237


                                 BREAKDOWN BY PERMEABILITY
                  ORIGINAL OIL IN PLACE          REMAINING OIL IN PLACE
LS TH 20                 41987                          23450
20 TO 50                 16640                          12763
50 TO 100                 8136                           6121
100 TO 500               35004                          23495
500 TO 1K                27204                          18749
GR TH 1K                 38490                          31109
UNKNOWN                 100679                          84429


                                 BREAKDOWN BY DEPTH
                  ORIGINAL OIL IN PLACE          REMAINING OIL IN PLACE
LS TH 500                    0                              0
500 TO 3000              98525                          78154
3000 TO 6000             80451                          57087
6000 TO 10000            72492                          59634
GR TH 10000               5306                           4084
UNKNOWN                  11366                          10358
```

The breakdown by permeability also implies relatively favorable conditions. The sample contains 63 billion barrels of estimated remaining oil of 100 millidarcies or above, as well as a relatively large 84 billion barrels for which permeability was not obtained.

The depth breakdown indicates the remaining oil in the sample is rather equally spread over the 0 to 10,000 foot range with over a third of the remaining oil-in-place at less than 3,000 feet.

However, with respect to secondary and tertiary recovery, it is the combination of reservoir parameters which counts. The program we have written to access the large field data file has the capability of taking as input a series of upper and lower bounds on reservoir parameters and returning the best estimate of the original and remaining oil in place which meets all these reservoir conditions. For example, the user can specify range restrictions corresponding to conditions wherein the remaining oil in place has a gravity value greater than 30 and less than 40 and a permeability greater than 100 and less than 500 and whose depth, porosity, etc., are all within separately specified ranges.

The program has the capability of taking as input as many as ten(10) of such sets of constraints. It will not only return the original and remaining oil-in-place which meets each constraint, but also the overlap between each of the paired sets of constraints--that oil which meets the conditions of both the ith set of constraints and the jth set of constraints. This capability is required if we are to avoid double counting in building up the recovery curve.

Implications for Enhanced Recovery

As we shall see in Chapter IV, of the tertiary methods, CO_2 is favored by high API gravity, requires a fair amount of pressure and is relatively insensitive to permeability. Micellar methods require high API gravity, relatively low depth, low temperature and moderately high permeabilities. Miscible hydrocarbon requires high pressure, high API gravity and high permeability. Steam drive is favored by moderately low API gravity, low depths, and requires high permeability. The conditions for combustion are similar to steam with the exception that at least moderate depths are required.

With this in mind, in order to obtain a very preliminary estimate of tertiary prospects for the remaining oil in the sample, the set of constraints shown in Figure III-7 were run through the partitioning program. Given the limitations of the data discussed earlier, the fact that we are ignoring both thickness and the very important current oil saturation, (two characteristics for which we have few reliable estimates) we should make a somewhat guarded interpretation of the figures shown in Figure III-7. Recall that while our major fields represent perhaps 70% of all the remaining oil-in-place, for over one third of this oil no permeability data was available. Hence, the fields represented in Figure III-7 correspond to roughly one-half of all the already discovered oil in the United States. Thus one might, as a very rough approximation, double these numbers. Even so, the results are none too optimistic regarding recovery prospects. In advance of the detailed discussions in Chapter IV, let us comment on some of these implications here.

CO_2 has perhaps the broadest range of applicability, but as indicated in the Chapter IV section on CO_2, its economics are sharply dependent on distance to source of CO_2. This distance variable has not been considered in Figure III-5. Further, an unfavorable mobility ratio implies CO_2 effectiveness is sharply dependent on reservoir homogeneity, another variable not represented in the table. Finally, most CO_2 projects are targeted to obtain less than 15% of the oil remaining in place after waterflood.

FIGURE III - 7

PRELIMINARY BREAKDOWN OF OIL IN PARTITIONED SAMPLE

ALL FIGURES IN BILLIONS OF BARRELS[1]

	MIN API	MAX API	MIN PERM	MAX PERM	MIN DEPTH	MAX DEPTH	MIN POROS	MAX POROS	ORIG OIL IN PLACE	REMAIN OIL IN PLACE
'CO_2'	35	--	--	--	3000	--	--	--	54	36
'MICELLAR'	35	--	100	--	--	6000	--	--	19	12
"MISC. HC '[2]	40	--	100	--	5000	--	--	--	5	3
'STEAM DRIVE'	15	30	1000	--	--	5000	--	--	24	20
'COMBUSTION'	10	25	1000	--	1500	--	--	--	27	22

OVERLAPS[3]
REMAINING OIL IN PLACE

	'MICELLAR'	'MISC HC'[2]	'STEAM DRIVE'	'COMBUSTION'
'CO_2'	10	3	0	0
'MICELLAR'		2	0	0
'MISC HC'			0	0
'STEAM DRIVE'				19

Notes:

[1] See Figure III-1 for appropriate units for other descriptors (e.g. porosity).
[2] 'misc HC' corresponds to miscible hydrocarbons
[3] Refer to text for explanation of partitioning and the interpretation of "overlaps".

The results for micellar and miscible hydrocarbon are still less optimistic. As indicated in the Chapter IV sections on thermal methods, the total target for thermal is about forty billion barrels remaining oil-in-place of which we can hope to get about 50%. Yet of this amount, some ten billion barrels are already represented in the OGJ recoverables. The table also emphasizes the strong overlap within thermal between steam and combustion methods.

IV. SECONDARY AND TERTIARY RECOVERY

Overview and Perspective

The definition of "enhanced recovery methods" as used, for example. by the oil and gas regulatory bodies of the 30 states comprising the Interstate Oil Compact is production of crude oil from reservoirs through actions taken to enhance primary reservoir drive, via pressure maintenance, waterflooding, gas injection miscible fluid displacement, microemulsion flooding, in-situ combustion, cyclic steam injection, steam flooding, CO_2 injection, polymer flooding, caustic injection, or similar techniques.

For our purposes, we have arbitrarily defined in our project secondary recovery[1] methods as immiscible gas injection and water flood or combinations of both. The major tertiary methods we define as:

- hydrocarbon miscible
- CO_2 and inert gas miscible
- micellar miscible
- steam drive (cyclic and full flood)
- in-situ combustion ("fireflood").

These methods will be discussed in great detail in the following sections of this chapter. Essentially, however, the secondary methods are aimed strictly at maintaining reservoir pressure at levels adequate to prevent production cut-off beyond the point at which the reservoir's inherent driving forces cease to be effective. Given that beyond a certain point 50% or more of the original oil may still be in place for a typical reservoir undergoing pressure maintenance, there has been considerable interest in methods which go beyond secondary recovery. These methods attempt not only to apply pressure to the oil but also to alter the forces which hold the oil in place. These major tertiary methods fall into two basic categories:

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[1] Infill drilling projects are not addressed here since such practices tend more to accelerate the rate of already achievable recovery rather than enhance the absolute level of recovery. However, the use of infill drilling in tandem with a tertiary recovery method can often prove to be a very effective combination from the standpoint of present value economics.

- miscible methods aimed at reducing the surface tension forces between the oil and the driving fluid;
- thermal methods which are aimed at reducing the viscosity of the oil by heating as well as in some cases changing the chemical character of the oil.

It is the assessment of both the technological and economic feasibility of applying these secondary and tertiary methods given the in-situ characteristics of remaining oil volumes which we will discuss in detail in the following sections of this chapter.

Secondary Recovery Methods

Gas Reinjection

(i) Existent Practice

Gas reinjection methods have been widely utilized for many years. The practice of regulating gas well below its energy equivalent price has resulted in an economic situation where it pays the operator to reinject associated gas even when the increase in oil recovery is even rather marginal. According to our gas drive reservoir model, under oil/gas price ratios prevailing in the United States prior to recent price jumps, it pays an operator to reinject rather large proportions (60-80%) of produced gas over a wide range of gas drive reservoir parameters. This is especially true if the operator expects gas prices to rise at rates higher than his cost of capital. Some OCS leases are reinjecting gas because the marginal cost of transporting the gas to shore has been less than the market price. In short, due to low gas prices relative to oil, expectations of future rises in price and environmental restrictions, there has been considerable reinjection in the past. Thus, we could reasonably expect that increases in oil production associated wtih such pressure maintenance programs would already be reflected in API recoverable figures.

(ii) Cost-Performance Characteristics

A major problem with gas reinjection is its inefficiency. Runs of our gas drive model indicate that for typical gas solution drive fields, reinjection will only increase oil recovery from the neighborhood of 15-20% of the original oil-in-place to perhaps 25%, still leaving the great bulk of the oil in the ground. This is due largely to the unfavorable mobility ratio.[1] Since waterflood is usually much more efficient, it will generally dominate gas reinjection as soon as prices support the more expensive waterflood. As we shall indicate later, this has already happened in the United States. For example, in 1970 it was reported that only 208 of the more than 3,000 injection and pressure maintenance projects in Texas used gas as the injection fluid.

Occasionally, gas reinjection can be used in conjunction with waterflood as is done by Creole in Lake Maracaibo, where gas is injected into the cap with water down dip. The gas prevents the oil from pushing into the gas cap, thus wetting additional rock. However, this technique is useful only in certain rather specialized cases. Even then, the differences with and without gas injection are not striking.

Gas injection can also be used sequentially in conjunction with waterflood. In water wet reservoirs, capillary forces will tend to pull the water through the narrow passages, bypassing the wider passages. The opposite will tend to happen with gas. Thus, in some cases, extra production can be obtained by cycling gas and water injection.

We have encountered only one sizable project of this type--an Amoco project in the Gillock South field in Galveston, Texas, approved in 1965. This project has since been superseded by a CO_2 flood approved in 1971. One of the problems of gas injection relative to water injection is the comparatively higher cost of compression as opposed to pumping. Again, for the Gillock South field, of the total cost of the secondary recovery of $4 million, $1.8 million was the initial cost of gas injection facilities and $1.7 million was the operating cost of the gas systems. In return, the project yielded an additional 7-8% of OOIP (8.9 million barrels) at a marginal cost of roughly 50¢ per barrel. Similar proportionate increases in recovery via gas reinjection were indicated in our earlier model runs for Prudhoe Bay.

---

[1] The mobility of a fluid in a reservoir is equal to the ratio of the permeability to viscosity of that fluid. The mobility ratio, then, is equal to the ratio of the mobility of the displacing fluid to the fluid being displaced.

(iii) Future Recovery Prospects

In summary, future prospects for gas injection[1] are (a) sharply limited by the fact that gas is probably the least effective displacement mechanism of all the alternatives and (b) whatever its potential, it is probably already reflected in the API recoverable estimates. Gas injection will continue to be used for pressure maintenance purposes and to prevent oil from migrating into gas caps, but there is no reason to believe that gas injection can make a sizable dent in the recovery of oil presently listed as unrecoverable. Moreover, we should expect little additional gas reinjection as recent and near-term anticipated gas price rises make OCS gas economical to land and decrease operator's expectations of future gas price rise. Also increased oil prices make more thorough oil recovery methods economical in fields which were marginal. Even if gas reinjection were increased, it could have little overall effect on the oil supply curve due to its inefficiency.

Waterflood

(i) Existent Practice

Waterflood has also been used extensively in the past, to the point where one industry observer comments, "Opportunities are dwindling rapidly to add to domestic supplies from existing fields [by waterflood]"[13].

---

[1] To be clearly distinguished from high-pressure, miscible hydrocarbon displacement.

Waterflooding dates back to the 1890's when it was practiced illegally (for fear of "contaminating" the oil) in the Bradford Field in Pennsylvania. It was not until 1921 that waterflooding was made legal. Afterwards, the practice spread rapidly into the Midwest, thence to the midcontinent and, finally, to the Gulf Coast.

The practice has become so extensive that in 1970 in Texas there were 2,821 active water injection projects covering more than 1000 fields.[14] In our survey of Texas giants, we have yet to discover a field of this type which has not been subject to waterflood. In Louisiana, there were 347 water injection projects active in 1972.[15] In Illinois, 70% to 80% of all production is on waterflood.[16] In 1963, there were 867 waterflood projects in Oklahoma, covering all the big fields.[17] In Nebraska, hardly a truly productive area, there were 49 projects in 1965. For these small stratographic traps, waterflooding was so extreme that out of the 129 million barrels of oil expected to be recovered in Nebraska, waterflooding was given credit for 60 million barrels.[18] In Wyoming in 1968, there were 138 active waterfloods covering 65 fields, including all the big ones.[19]

The basic problem with waterflood, from our point of view, is that it appears to have been quite economical at prices below those prevailing before the 1972-1973 jump, that is $3.00 per barrel or less. Waterfloods in the eastern half of the United States date back to the 1930s. The mid-1950s also saw a great number of waterflood projects begun in the midcontinent. Even in high transport-cost-to-market areas such as Alaska, considerable water injection has been practiced. The Cook Inlet fields have been on water almost since first production and now have 60 injection wells. The Grand Ile 16 field (Gulf of Mexico) in 1973 had 56 producing and 20 water injection wells in use for some time, a practice considered typical for the larger mature fields in the Gulf.

Even in foreign countries, when the price of oil was $2.00 per barrel and less, considerable waterflood was taking place. In Canada in 1966, over 100 separate fields were under waterflood, including the four largest. Fullscale waterflooding of the 400,000 acre Pembina Cardium Field[1] in Alberta was initiated in 1956, three years after discovery. Some water injection has even been practiced in Venezuela. In 1964, when the price (in 1974 dollars) of oil f.o.b. Venezuela must have been less than $2.00, there were 25 plants in operation, injecting 550,000 bpd into 29 reservoirs. Even in the Middle East, there has been some waterflood. Iraq has been injecting water into the Kirkuk Field since 1971, when the 1974 dollar price of that oil was no more than $1.50. Abquaia Field in Saudi Arabia has been on water since 1957, and the Ghawar Field was injecting 363,000 bpd in 1966.

(ii) Cost-Performance Characteristics

The information we have analyzed relative to existent practice seems to point to the fact that we may not see much additional oil from conventional waterflooding due to the $3.00 to $10.00 per barrel price rise because its economic viability at $3.00 per barrel appears so substantial.

This is most unfortunate, because waterflooding is a rather efficient means of increasing recovery as the examples in Figure IV-1 would indicate. For a typical gas depletion field with oil above 30° API, waterflood will increase recovery from the range 15%-20% to 30%-45%. Unfortunately, it appears likely that most if not all this oil is already accounted for in the API recoverable figures since it could economically be recovered at $3.00 per barrel or less.

---

[1] This is cretaceous, low permeability sand at 5,100 feet.

FIGURE IV - 1

INCREASED RECOVERY VIA WATERFLOOD

ILLUSTRATIVE EFFECTS FOR SELECTED FIELDS

FIELD	CHARACTERISTICS	RECOVERY	
		PRIMARY	WATERFLOOD*
Eldorado	Sandstone, D=650', H=10-30%; k=150-1500 md.; 37° API; 4 cp at 70°F.	21%	43%
Jay		17%	48%
Pembina Cardium	Cretaceous sand, thin; D=5100'; low, irregular permeability	15%	~30%
Swan Hills	Devonian reef; downdip peripheral	17%	44%
Weyburn		14%	31%
West Burk Burnett	Gunsite Sand	15%	32%

*Total, not incremental, recovery. Thus, in the Eldorado Field, waterflood recovered an additional 22% (43-21) of the OOIP after primary.

Geffen[13] places the average cost of waterflood recovery at 30¢ to 50¢ per barrel as past practice, which is consistent with the behavior described above.

Mobil in the S.E. Breckenridge unit of the Stephens Regular Field charged the other interests:

$60 per injection well per month in maintenance
"plus" $0.0048 per barrel water injected
"plus" .000305 x PSI x KWHC (PSI is injection pressure in psi and KWHC is dollars per kwh)

This contract was signed in 1973.

The Dickie unit in the same field estimated a cost of $405,000 to obtain an additional 630,000 barrels, while the Jones unit estimated a cost of $492,000 to obtain an additional 1.2 million barrels.

The Baker-Ackers unit is paying 25¢ per thousand gallons from the West Texas Municipal Water Authority on a 1968 long-term (20 year) contract.

In 1965 it was reported that in Texas, waterflood projects were averaging 8.2 barrels of water injected for each additional barrel of oil recovered. But in both Texas and Oklahoma, projects with 20 to 1 ratios were common. At 25¢ per thousand gallons and 20:1, the water cost per barrel of oil recovered is about 20¢.

The initial cost of a rather large project in the Seminole Field involving 65 injection wells with a capacity of 195,000 bwd[1] was put at $2.9 million on average. This project hoped to recover an additional 115 million barrels of oil.

In short, all the data we have seen so far substantiates Geffen's claim that even the rather extensive waterflooding which has taken place in the past rarely costs over 50¢ per barrel on average, and sometimes a good deal less.

---

[1] bwd, "barrels of water per day".

However, some recent reports on new projects indicate somewhat higher costs. A new five spot waterflood replacing gas injection in the Alvord Field is reported to cost $1.5 million to get 2.4 million barrels additional oil at a rate of 600-1000 bpd. This is roughly about $1.50 per barrel present valued. At a still higher cost, Mosbacker, a Houston independent, claims he will spend $10 million to obtain 3-4 million additional barrels. The Jay Field waterflood, operating under very difficult conditions (high depth, pressure, temperature, and sulphur content) is costing $19.5 million to inject 200,000 barrels per day. But this investment is expected to increase production by 217 million barrels.

(iii) Future Recovery Prospects

The prospects that recent price rises will induce significant increased recovery via conventional waterflood[1] appear dim. It appears also that most all the large fields have been subject to extensive waterflooding for some time and it is likely that the impact of this waterflooding is reflected in the present API estimates of recoverable reserves.

However, we should add that some commentators have taken a more optimistic view regarding these API recoverables estimates. They note that:

- the only oil booked into the API recoverable figures is that in the spacing actually drilled and associated offsets. Thus, a discovery is not completely represented in the recoverables until the field is fully developed.
- secondary oil is not counted until the injection prospects are in place and field tests have proved successful.

---

[1] Assuming existent state-of-the-art waterflood practice.

While it is true that discoveries are initially grossly underrepresented and that accordingly, extensions and revisions typically average 5 to 6 times the reported new field discoveries, the present effect of this time lag is unlikely to be large for two reasons:

- As noted earlier, we have not discovered that much new oil recently. Almost all our large fields are old enough to have been fully developed for some time. Waterfloods have been in place on most of these fields for a decade or more. Thus, the effects of these inventory reporting lags for the vast bulk of our already discovered oil are,for the most part, behind us.
- In these times, new discoveries are developed very quickly. The Jay field which was discovered in 1970 was completely developed by the end of 1973 including an extensive waterflood project, despite the difficult reservoir problems alluded to earlier. In 1974 Jay production was 33 million barrels (ranking the field eighth in the entire United States for that year) despite the fact that, in terms of ultimate recovery, it ranks about 70th of all U.S. discoveries.

It would be most interesting to know what the current API estimate of the ultimate recovery is for Jay and other large fields. In fact, such information is absolutely basic to any analysis of enhanced recovery. It is impossible to say how much we could add to current API field estimates if in the first place, we are unaware as to what these estimates now are. Unfortunately, API has a strict policy of not revealing estimates on individual fields. Whatever the rationale for this policy, it still stands, and therefore we must search for a proxy.

The proxy for the API recoverable estimates for the large fields which we have used are the Oil and Gas Journal large field estimates published annually in the Oil and Gas Journal and the International Petroleum Encyclopedia.[1] As a working hypothesis, we have assumed that the OGJ estimates by field are equal to the API estimates.

There are two major arguments for this assumption:

- The first is bureaucratic. The individual who is supplying the field estimate to API would be the logical source to whom the OGJ inquiry would be referred. This person would be placed in a difficult situation if it became known that he were supplying two different estimates.
- The second and stronger argument is that the API representative's company as a whole would be viewed in a very unfavorable light by the public if it became known that it were supplying two significantly different estimates. The company really has nothing to gain from giving the OGJ a different estimate from that supplied API and it most certainly has something to lose.

Therefore, we have proceeded on the assumption that the current OGJ recoverable estimates are equal to the current API recoverable estimates.[2]

The current OGJ estimates of ultimate recovery for the Jay field is 312 million barrels, about 45% of the oil-in-place of this non-water drive field. This figure then certainly includes the great bulk of all secondary recovery to be expected from this field. If Jay is representative it seems as if the lag between initial discovery and the appearance of secondary oil in the API estimates may have dropped to something less than 5 years.

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[1] See Chapter III discussions on the Big Fields file.

[2] This assumption remains an unproven hypothesis and this should be kept in mind in evaluating our results.

The remaining question with respect to waterflood potential then is: if the average cost of waterflooding to achieve roughly 50% recovery of the original oil in place is $2.50 per barrel or less, will the price rise of the last three years result in still more extensive waterflooding with additional recovery?

The answer to this question depends of course on the marginal cost of waterflooding. In order to address this question, at least in a preliminary fashion, a two-dimensional, two phase finite difference reservoir model was constructed.[1] The inputs to this program are reservoir characteristics specified on a vertical grid, including the permeabilities to oil and water, a waterflood injection rate through time and initial oil and water saturation as a function of oil saturation. The output values are the three pressure histories, oil and water saturations at the grid points, and the oil and water production through time. Figure IV-2 shows some typical output of this program. The important thing to note is that most of the oil is produced at rather low water/oil ratios during the first three years of the project's life. After this the rate of oil production falls off very rapidly and the producing water/oil ratio climbs sharply. The reasons for this extremely non-linear behavior is the fact that as the water saturation increases in the reservoir, the formation becomes increasingly impermeable to oil and increasingly permeable to water. While the numbers vary from field to field, all reservoirs exhibit this unfortunate property. As a result, in the latter life of the waterflood almost all the water being injected is bypassing the remaining oil.

Since for constant injection rates, waterflood operational costs per unit of oil produced are roughly proportional to the producing water/oil ratio, this ratio can serve as a proxy to the marginal cost curve. At a cost of $1.00 per barrel of

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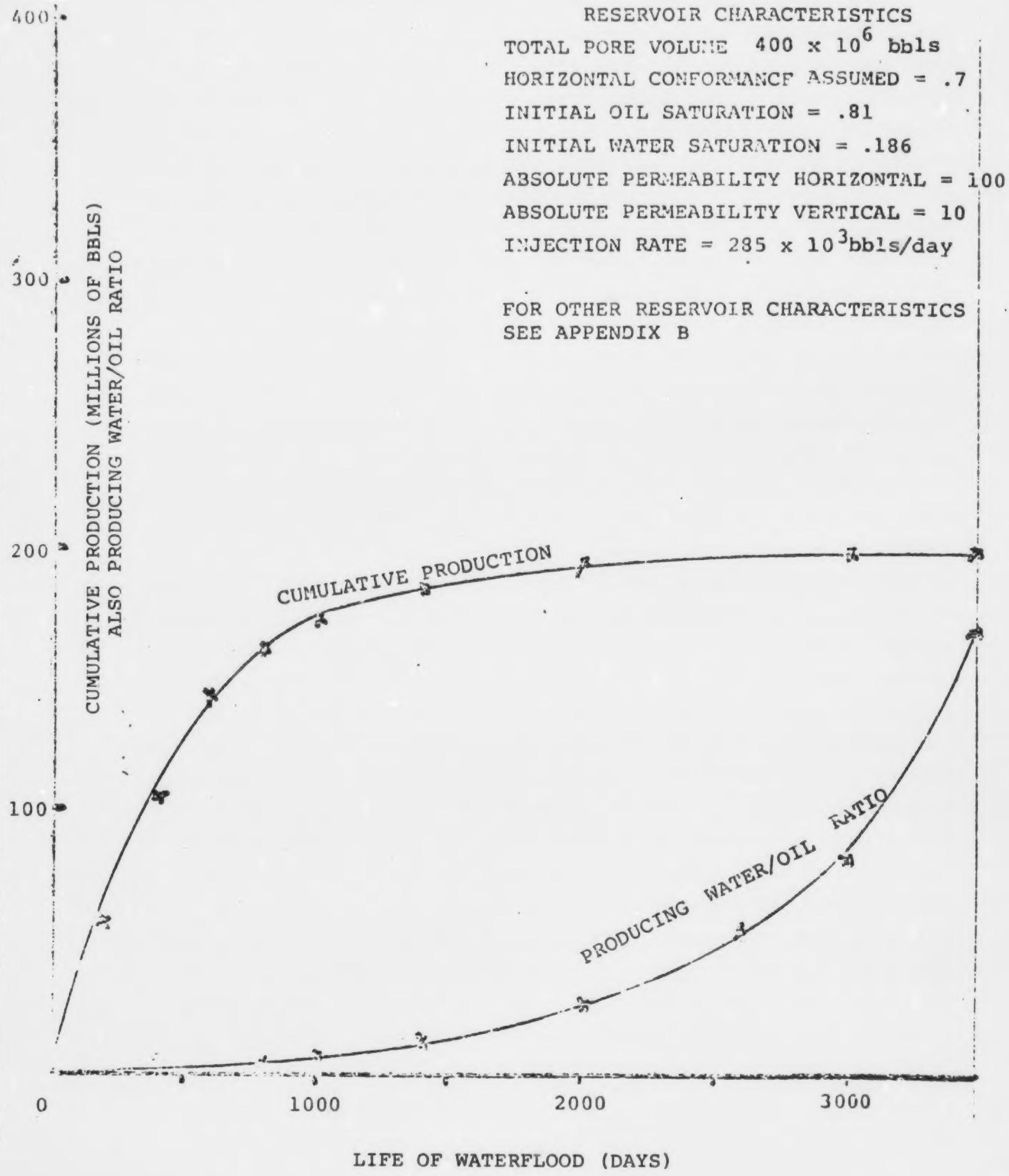
[1] See Appendix B for a description of the model.

FIGURE IV - 2

RECOVERY RESPONSE IN A PURE WATERFLOOD RESERVOIR

ILLUSTRATIVE MODEL RESULTS



oil, the cut-off appears to be in the neighborhood of 50:1 to 100:1 depending on the reservoir. At this point most of the oil that can be produced by waterflood has been produced, and the marginal costs of obtaining further oil escalates rapidly. Injection water treatment, injection and separation costs of 5-10¢ per barrel (even assuming all equipment is in place) are not unreasonable. With such costs tripling the price of oil from $4.00 to $12.00 might double the water/oil cut-off ratio from say 75:1 to 150:1. However, due to the non-linear response of the reservoir, the doubling of this producing ratio will typically increase overall cumulative reservoir production to the extent of only 2 or 3 percent. The shape of this curve then explains the paradox of average unit costs at levels much lower than market price on past waterfloods and the relative insensitivity to even rather large jumps in price.[1]

The above figures were based on a homogeneous reservoir. All reservoirs have spatial variations in permeability which, when combined with the non-linear process outlined above, leads to unstable behavior known as "channeling" or "fingering" in which the drive water channels through the high permeability streaks bypassing the oil in the low permeability areas, thereby further aggravating the entire problem. Attempts have been made to combat these difficulties by artificially increasing the viscosity of the drive water through the addition of polymers. However, to date the performance of pilot tests (as we shall discuss later) has proven disappointing.

In summary, while it appears very likley that the life of many waterflood projects will be extended by the price rises and that many previously abandoned fields may be reopened, we do not feel that this increased secondary activity will add more than a percentage or two to the ultimate recoveries. An additional 3% rise in ultimate recovery (about 1% of original oil-in-place) would be about 5 billion barrels. This, of course, is not an insignificant amount of oil. Unfortunately, almost all of it will be high cost oil, essentially a breakeven proposition even at present prices. Moreover, this additional oil will not increase national income nearly as much as, for instance, a five billion barrel discovery on the OCS or in Alaska. It should also be remembered that five billion barrels is a good deal less than one year's consumption at current rates.

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[1] The shape of this curve would be different for oil wet reservoirs. However, the great bulk of all U.S. fields are water wet.

Tertiary Recovery: Miscible Methods

Hydrocarbon Miscible Methods

(i) Existent Practice

One of the key problems in oil recovery in oil wet reservoirs is overcoming the surface tension forces which tends to bind the oil to the rock. In water wet reservoirs surface tension forces act to creat bubbles of oil which can block pore passages as the bubbles resist the increased surface area associated with squeezing through these passages. These surface tension forces are the primary reason why reservoirs become increasingly impermeable to oil relative to water as water saturation increases. If one can reduce the interfacial tension between the oil and the driving fluid, then these forces are reduced. This is the object of miscible floods.

One form of miscible flood involves using a slug of light hydrocarbons under high pressure followed by a waterflood. According to the Oil and Gas Journal, there have been 13 field-wide hydrocarbon floods, four of which have been terminated.[20] Three of these completed floods were termed "successful." However, only one field-wide and two pilot studies have been started in the last three years. While under ideal laboratory conditions, miscible hydrocarbon flooding can recover all the remaining oil, the completed projects report residual oil saturations of one-half to two-thirds, the initial saturation.

(ii) Cost-Performance Characteristics

The biggest high-pressure hydrocarbon flood undertaken in the United States has been the Hunt project in 22,600 acres of the Fairway Field. This is a deep 10,000 foot limestone formation with moderately low permeability (22 millidarcies), moderate porosity, (11%) and an average thickness of 70 feet. Original oil-in-place is estimated at 400 million barrels. The oil is very light (48°API), volatile (current GOR 3317 cu.ft./bbl) and fluid (viscosity .15 cp at reservoir conditions). Gas is being injected at 4500 psi. In a 1966 prospectus, Hunt claimed:

Recovery Method	Incremental Recovery (MMBBLS)	Cumulative Recovery (% OOIP)
Primary	96	24%
Waterflood	+106	51%
HP-Gas	+178	70%

In Hunt's 1966 prospectus, the cost of the project was placed at $4 million, including $1 million for compression equipment and $2 million for gas. If true, this would make this project extremely attractive at old prices.[1]

Other than the Fairway project there have been no field wide hydrocarbon miscible projects started in the past few years and our interview indicated very little current interest in the method. The method suffers from several problems. Since high pressures are required, the method is limited to fairly deep fields both to avoid the cost of repressuring and the threat of blowing through the overburden. The method is energy intensive both because the slug is hydrocarbon and more importantly because of the amount of compression required. Most important, however, the method suffers from a very poor mobility ratio. As discussed earlier, the mobility ratio is a measure of the ease with which the driving fluid moves through the formation relative to that with which the reservoir fluid moves. If this ratio is high, the driving fluid tends to "finger" the oil and channel through high permeability streaks. The net effect is that the driving fluid begins to recirculate rather than expulse oil. This is much the same problem that plagues waterflood. The resultant implication is that miscible hydrocarbon flooding is limited to very high API oils where the mobility ratio is not so unfavorable.

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[1] As of 1/1/75, 124 MMBBLS had been produced from this field. As an aside, the current OGJ ultimate recoverable for Fairway is 210 MMBBLS which, if one believes the original Hunt prospectus, assumes a successful waterflood but does not count the projected increases over waterflood due to the high pressure gas.

(iii) Future Recovery Prospects

We saw in Chapter III that less than 12% of the discovered remaining oil in place is lighter than 40°. On the basis of the earlier discussed problems with this method and the apparent lack of interest operators have expressed in it, we did not assess the potential of hydrocarbon recovery in detail. However, we believe it would be imprudent to count on hydrocarbon miscible for more than a billion or so barrels of additional recovery even at today's prevailing prices.

Miscible CO_2 Flood Methods

(i) Existent Practice

Another approach to miscible displacement is CO_2 flooding. CO_2 is miscible with oil at pressures somewhat lower than those of high pressure gas. At these pressures CO_2 is also highly soluble in oil. Most of the carbon dioxide is injected in a slug which leaves the water and enters the oil. This reduces the viscosity of the oil and increases both its bulk and relative permeability. CO_2 also reduces the interfacial tension between oil and water. The Oil and Gas Journal survey presently lists three full-scale CO_2 projects and four pilots.

(ii) Cost-Performance Characteristics

In the currently active CO_2 projects, API gravities range from 32° to 42° with low viscosities. Depths are high, 4,300 feet to 9,000 feet and permeabilities are low, 2-10 md.

The largest CO_2 project is the 50,000 acre Sacroc Unit encompassing the entire Kelly-Snyder Field. This is a limestone reservoir at 6,700 feet in which the primary recovery mechanism was solution gas drive with no gas cap. Initial pressure was 3122 psi; current pressure is 2400 psi; porosity is only 7.6%; permeability averages 9.4 md; net pay thickness is 213 feet; connate water saturation is 36%; gravity is 42°, viscosity is .375 cps at reservoir conditions. Original oil-in-place is about 2.7 billion barrels, of which some 600 million had been produced at the beginning of 1973. The field had been subject to a centerline drive water injection program. This waterflood has proved very effective with a sweep efficiency of 72% and a residual water cut of 26%. However, after waterflood, about 1.5 billion barrels would be left.

The CO_2 flood is aimed at reducing residual oil saturation, not increasing sweep efficiency.[1] The Sacroc plan involved injecting 50 million cfd[2] of CO_2 up to 20% of pore volume or 579 billion cubic feet of CO_2 over ten years. The CO_2 flood was to be followed by waterflood. CO_2 would be miscible with the light crude at 1,850 psi. Injection pressure would be 3,000 psi; volume 3,000 mcfd[3] per well.

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[1] The CO_2 will not initially reach areas of the reservoir which are not reached by the waterflood due to the less favorable mobility ratio.

[2] cfd is "cubic feet per day."

[3] mcfd is "thousand cubic feet per day."

Chevron, the project's operator, claimed lab tests indicated that residual oil saturation would be 0% in swept part of reservoir and that the CO_2 flood would net 156 million barrels. In 1969, the projected cost of this CO_2 flood including the 200 mile, 18-20" pipeline and 5¢/hcf[1] for the gas totaled $120 million. In 1974 operators reported total CO_2 cost estimates had risen to $140 million plus another $75 million for the waterflood. Using these figures and computing a present value at 10% return, the cost per unit of oil works out to be about $2.50 per barrel.

Chevron also had examined hydrocarbon miscible flood but claims HP gas would not work because reservoir pressure is too low for miscibility. Enriched gas would require a 15% slug to get 115 million additional barrels. Chevron claims it would cost $57 million more than CO_2 and obtain 41 million less barrels.

Another large (5900 acre) CO_2 project is that undertaken in 1971 by Amoco in the Gillock South Field. This also involved a light (38° API), low viscosity (.64 @ 214°F) crude. The reservoir was at a depth of 9000 feet with moderate pressures (3300 psi). However, the field is a sandstone formation of high permeability (1156 md) and porosity (30%), typical of the Gulf Coast. This field had been subject to a combined gas injection-water injection program and primary plus secondary operations produced an aggregate recovery of 65% OOIP, 93 MMBLS in all. The secondary operations accounted for 8.9 MMBL over primary under good water drive. Amoco claims they can enhance this 65% to 78% by CO_2 flood for a net tertiary recovery of 11.2 million barrels. Amoco, like Chevron, claims all oil contacted by CO_2 will be recovered. The 78% then is essentially the sweep efficiency.

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[1] hcf is "hundred cubic feet."

Amoco plans to use six injection wells, injecting 10,000 reservoir barrels of CO_2 (500 tons or 8500 mcf surface) per day while phasing out the waterflood. The initial costs of the project were put at $1.5 million and operating costs at $18 million. Amoco is buying CO_2 from an ammonia plant in Texas City. About $15 million of the operating costs were the CO_2, which assuming a project life of 10 years, puts the cost of CO_2 at about $6 per ton or 60¢ per reservoir barrel. If these figures are correct, the cost per additional barrel is then about $1.50.

A third large CO_2 project is that being undertaken by Shell in the Crosset Field in West Texas. This reservoir is a fine grained chalk. Permeability is low (3 md), but unusually uniform. This field is a rare exception in that it has never been waterflooded because water would cement this unusual formation. Porosity, at 21% is moderate; API gravity is 42°, miscibility pressure is 1650 psi. Shell is using a 93% CO_2, 7% CH_4 mixture from the Sacroc pipeline which passes within just a few miles of Crosset. Injection started in mid-1972 with no results as yet. Shell planned to use 73 billion cubic feet over 10 years at a rate of 20,000 mcf/day and to reinject produced gas as is.

Recently Shell also started a pilot project in the Little Creek Field in Mississippi in which they are paying $25/ton for CO_2, delivered to the field by truck.

As the discussions above would indicate, there are basically two problems associated with CO_2 flooding:

- the compression and transport of CO_2 is expensive and extremely energy intensive;
- the mobility ratio, while not as bad as that for high pressure hydrocarbon, is still quite unfavorable for most reservoirs.

CO_2 is a common byproduct of industrial processes and would appear at first to be almost a free good. Unfortunately, however, the available CO_2 is rarely in the form or location desired. CO_2 concentrations in industrial stack gas run 10-13%. Practically pure CO_2 is available at certain chemical plants, such as ammonia facilities, but rarely in the volumes required. Also, byproduct CO_2 is usually available at atmospheric pressure. The economics of pipelining CO_2 are such that it is best maintained above critical pressure. This generally requires pipeline injection pressure of 2000 psi or more. For field injection into reservoirs, pressures of 3000 psi are often indicated. It takes approximately 0.015 barrels of oil as fuel to compress 1000 cubic feet of CO_2 from atmospheric pressure to 3000 psi or, at present prices, about 16¢/mcf in fuel costs.

CO_2 is available at pressure as a natural resource generally in association with gas. However, the geologic events required to form large quantities of CO_2 are relatively rare and always involve depths in excess of 15,000 feet wich imply expensive wells. In the Val Verde Basin large quantities of CO_2 are produced in association with gas. Unfortunately, this is not a common phenomenon.

Transporting CO_2 is somewhat more expensive than transporting an equivalent amount of natural gas the same distance. Higher pressure and hence heavier walled pipe are indicated. The cost of transporting the SACROC CO_2 200 miles by 18-20" pipeline has been placed at 25¢/mcf at 1972 prices. Inflation since then implies that total transport costs in terms of 1974 dollars will be in the neighborhood of 20¢/mcf per 100 miles.

At 2000 psi and normal temperatures, it takes about 820 surface cubic feet of CO_2 to equal one reservoir barrel; at 3000 psi about 1125 cubic feet. Typical production plans for

CO_2 projects necessitate injecting 15 to 30% of pore volume followed by water. Most of the operators report target recoveries of about 10% of the remaining oil in place.

The costs per unit of oil recovered as a function of both distance to 'free' source of CO_2 at atmospheric pressure and current oil saturation are shown in Figure IV-3. The figures shown are exclusive of all costs other than those of delivering and injecting the CO_2 and assume an equivalence of 1000 cubic feet per reservoir barrel and a 20% pore volume slug. The obvious implication of these figures, of course, is that the distance to the source of CO_2 is an extremely important variable in determining the prospects for tertiary yield from CO_2.

A second basic problem associated with CO_2 is, once again, unfavorable mobility ratios which lead to an unstable slug/oil interface. This was dramatically illustrated recently by the premature breakthrough of CO_2 in the Sacroc project. The operators had calculated that initial breakthrough would occur two years after start of injection. Actual breakthrough occurred in two months. Once breakthrough occurs, there is very little one can do about it other than to begin recirculating and recompressing CO_2. The Sacroc operators are attempting a "sandwich" technique in which they alternatively cycle water and CO_2 injection at short intervals. Poor mobility ratios lend to poor conformance and effectively confine the method to light crudes. Also, as gravity decreases, the pressure required to obtain miscibility increases. Certainly, any oil which was not reached by the preceding waterflood due to limited sweep efficiency will not be reached by CO_2 in the absence of additional drilling. No premature breakthrough has been reported by Shell in North Crosset, but as mentioned earlier, this reservoir exhibits exceptionally little variation in permeability.

FIGURE IV - 3

UNIT COST OF CO_2 RECOVERY AS A FUNCTION OF OIL SATURATION AND DISTANCE TO CO_2 SOURCE

(EXCLUSIVE OF WELL MAINTENANCE, SEPARATION AND WATERFLOOD)

DISTANCE TO SOURCE (miles)	OIL SATURATION		
	30%	45%	60%
0	1.00	.75	.50
100	2.33	1.55	1.75
200	3.66	2.77	1.83
500	7.69	5.12	3.84
1000	15.32	10.21	7.66

(iii) Future Recovery Prospects

In our opinion CO_2 appears to be the most promising of the methods which aim at miscibility. However, even at present prices it will be limited to high gravity fields in relatively close proximity to substantial sources of CO_2. Due to poor conformance it will be difficult even in these fields to obtain more than 10-15% of the oil remaining after waterflood. It remains to be seen how low in API gravity one can go with this technique. Shell is considering CO_2 for the 32°-35° Wasson field but apparently has yet to make a firm decision. In short, while there are a number of fields with high API gravity, gas drive, near CO_2 sources, for which a CO_2 project would be quite attractive at present prices, we feel it would be imprudent to count on CO_2 for more than 2.5-5.0 billion barrels of additional oil over that currently represented in the API recoverables.

Miscellar Polymer Flooding

(i) Existent Practice

If the immiscibility between oil and water is one of the basic problems facing enhanced recovery, the obvious question is why not go after the resulting surface tension forces in the same manner a housewife tackles the problem of cleaning oil off a greasy plate, namely via detergents or surfactants? Attempts at using injected surfactants to decrease the interfacial tension between oil and water are at least 40 years old. Unfortunately, in solution the expensive surfactant tends to precipitate out on the formation and quickly loses effectiveness. Our inquiries revealed very little current interest in surfactant flooding with the exception of a few quite exceptional fields containing natural surfactants which can be activated by relatively cheap injected material such as sodium hydroxide.

Micellar flooding is a variant on surfactant flooding in which a relatively small slug (5-10% pore volume) containing a relatively high concentration of surfactant (8-15%) is injected followed by a polymer thickened waterflood in which the concentration of polymer is slowly decreased. At the high surfactant concentrations employed, the molecules of surfactant tend to agglomerate into droplet-like systems known as micelles. These droplets can either be oil external or water external depending on oil/water concentrations. These micelles resist plating out (loss of formation) much better than ordinary surfactant solutions. However, plating can still be a problem and thus the slug is generally preceded by a preflush aimed at neutralizing active regions in the rock.

The micelles form a microemulsion which is miscible to both oil and water, thereby obtaining an effective reduction of surface tension forces within the slug. Just as importantly, it is relatively easy to obtain microemulsions whose viscosity is higher than the reservoir oil, thereby producing a favorable mobility ratio at the oil/slug interface which is relatively stable and resists fingering.

The problem is that the chemical components of the slug are so expensive that the volume of the slug must be kept much lower than the volume of the reservoir if the process is to be economical. This implies that the slug must be followed by a waterflood. Plain water would have an extremely unfavorable mobility ratio relative to the slug and quickly channel through the slug obviating the whole process. Therefore, the viscosity of this water must be increased by polymers. Since the polymer is also expensive, the polymer concentration is gradually dropped as the thickened water injection continues.

(ii) Cost Performance Characteristics

The most extensively tested of the micellar processes is Marathon Oil's Maraflood. In the Maraflood process, a slug consists of 7-12% surfactant (petroleum sulfonates), 1-3% cosurfactant (generally an alcohol), 25-50% hydrocarbons, and 25-70% water. The cosurfactant is a small molecule surfactant which tends to arrange itself between the molecules of petroleum sulfonate on the surface of the micelles stabilizing the structure and extending the range of concentrations and temperature over which the microemulsions will form. Both lease crudes and light fractions have been used for the hydrocarbon component.

The ingredients of the slug are rather expensive. Petroleum sulfonates are commercially available at about 32¢/lb of active ingredients.[1] Large scale micellar flooding would, in fact, put a severe strain on present sulfonate production facilities. Marathon is currently building a new facility in which they are aiming at reducing the cost to 20¢/lb active. The cost of the cosurfactant is about 30¢ per pound. Hence, assuming typical slug concentrations of 8% active surfactant, 2% cosurfactant and 25% lease crude, the slug cost is about $12.00 per barrel at 30¢/lb surfactant cost; $9.50 per barrel at 20¢/lb. surfactant cost.

The cost of the polymer thickened waterflood (often called the mobility buffer) depends primarily on the viscosity required at the front of the flood. This viscosity in turn depends on the viscosity of the slug which is determined by the mobilities of both the reservoir oil and reservoir water being displaced in front of the slug at the ambient oil and water saturations in this zone. For average waterflooded, medium gravity fields, this implies slug viscosities in the range of 20 to 30 centipoise. In order to obtain such viscosities in the mobility buffer, polymer concentrations of 1000 ppm or more are required depending on reservoir salts, flow velocity, etc. Polymer costs are in the neighborhood of $2.00 per pound although very large scale usage could bring this down. Polymer costs of $2.00 per pound and concentrations of 1000 ppm equate to an expensive $7.00 per barrel injected. Thus, the polymer concentration is slowly reduced as the mobility buffer is injected in an attempt to balance unfavorable mobility ratios with economics. Recent results are tending to mobility buffers of about 1% pore volume in which the average polymer concentration is about 750 ppm.

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[1] Commercial sulfonates generally contain about 62% active ingredients.

For the purposes of this study a simple computer program was constructed in which the key variables associated with micellar flooding could be varied and the resultant breakeven costs analyzed. The input to this program is shown in Figure IV-4.

The results of the analysis are shown in Figure IV-5. In main, they are rather discouraging. The best reported field test to date has recovered about 58% of the estimated oil-in-place remaining at beginning of the flood and some tests have reported less than 35% . Remember that since tertiary methods are generally tested on those reservoirs best suited for that method, the above quoted figures might be deemed rather optimistic estimates of recovery for less favorably suited fields.

(iii) Future Recovery Prospects

The effectiveness of this method is sharply dependent on oil saturation since the process is basically pore volume limited. One has to inject essentially the same volumes of slug and mobility buffer whether the reservoir contains 20% oil or 80% oil. Since any field well suited to micellar flooding will also be well suited to the much less expensive waterflooding, residual oil saturation of 45% or less is the viable target range of this method. According to our numbers, even assuming low end polymer and surfactant costs, at 45% residual oil saturation and 50% recovery, the process barely breaks even at present prices.[1]

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[1] A large scale field test of micellar in the El Dorado fields being constructed jointly by B.O.M. and Cities Service, if successful, will cost about $30/barrel produced. Even given the experimental nature of the project, this is a sobering figure.

FIGURE IV - 4

BREAKEVEN ANALYSIS OF MICELLAR FLOODING COSTS

MODEL INPUT VALUES

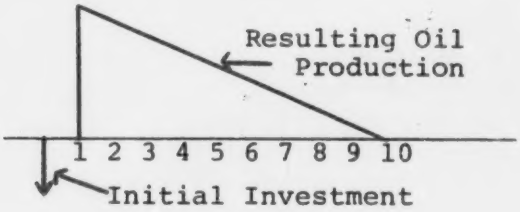
VARIABLE	ASSUMMED VALUE
Tertiary Oil Production Schedule	 Resulting Oil Production 1 2 3 4 5 6 7 8 9 10 Initial Investment
Real Cost of Capital	10% per annum
Well Investment	5¢/barrel pore volume
Slug Volume	5% pore volume
Slug Hydrocarbon Contents	25% slug volume
Operating Expenses	10¢/bbl fluid injected
Crude Price	$10.00/barrel
Mobility Buffer Volume	100% pore volume
Average polymer concentration	750 ppm
Buffer Injection Costs	6¢/bbl mobility buffer
Slug Injection Costs	50¢/bbl slug
Injection water	5¢/bbl
Water Drive Volume (post buffer)	200% pore volume
Oil saturation	25% to 45%
Oil Recovery	40% to 60%
Surfactent Price	15¢ to 30¢/lbs active
Polymer Price	$1.25/lb to $2.00/lb

FIGURE IV - 5

BREAKEVEN ANALYSIS OF MICELLAR FLOODING COSTS

REQUIRED PRICE PER BARREL OF CRUDE PRODUCED

SAMPLE MODEL OUTPUT

Surfactant Cost			15¢/lbs		22.5¢/lbs		30¢/lbs	
Polymer Cost			$1.25/lb	$2.00/lb	$1.25/lb	$2.00/lb	$1.25/lb	$2.00/lb
OIL SATURATION 25%	OIL RECOVERED	40%	$22.21	$25.42	$23.99	$27.20	$25.78	$28.98
		50%	$17.77	$20.33	$19.20	$21.76	$20.62	$23.19
		60%	$14.81	$16.94	$15.99	$18.13	$17.18	$19.32
OIL SATURATION 35%	OIL RECOVERED	40%	$15.87	$18.15	$17.14	$19.43	$18.41	$20.70
		50%	$12.69	$14.52	$13.71	$15.54	$14.73	$16.56
		60%	$10.57	$12.10	$11.43	$12.95	$12.27	$13.80
OIL SATURATION 45%	OIL RECOVERED	40%	$12.34	$14.12	$13.33	$15.12	$14.32	$16.10
		50%	$ 9.87	$11.29	$10.66	$12.09	$11.45	$12.88
		60%	$ 8.23	$ 9.41	$ 8.88	$10.07	$ 9.55	$10.73

We have seen also that the performance of pilot tests has proven disappointing, and the major manufacturer of the polymer has downgraded its polymer-thickened waterflood division despite the rise in price. This polymer costs about $1.50 per pound, or very roughly $500 per barrel. This again implies that it must be effective at low concentrations to be economic. Evidence to date indicates that such effectivenes has not been observed by field operators.

The costs of this method are about equally split between the slug and the mobility buffer with well and water injection costs being small. Since this method, like most tertiary methods has heavy front-end investment costs, perhaps the most fruitful avenue for increasing net present values is infill drilling to gain more rapid recovery of the oil. However, we have not examined this option in our current analysis.

In summary, we cannot be overly optimistic about micellar flooding. Even at present prices, it appears to be a breakeven proposition at best. We do not feel it would be prudent to count on micellar for more than a marginal amount of additional oil (perhaps less than 3 billion barrels) over that represented in the API reserves. Furthermore, much of this oil would be almost as costly to the nation as imported OPEC crude.

Tertiary Recovery: Thermal Methods

Thermal methods are aimed primarily at high viscosity, low API gravity crude. The idea is to apply heat to the crude which will:

- reduce the viscosity of the crude
- activate a solution gas drive in some instances
- result in thermal expansion of the oil and hence increased relative permeability
- create distillation and in some cases, thermal cracking of the oil.

Thermal methods are generally of three types:

(1) Steam soak (sometimes called steam stimulation or "huff and puff"). In this process, steam is injected down a producing well to heat up the area around the well bore and increase recovery of the oil immediately adjacent to the well. After injection for a short period, the well is placed back on production. This is essentially a well bore stimulation technique, each well responding independently.

(2) Steam drive (sometimes referred to as steam displacement). Here steam is injected via injection wells and the oil is displaced to surrounding producing wells as in conventional fluid injection operations.

(3) Combustion (sometimes called "fireflood"). This process involves in situ combustion of portions of the oil. Air is pumped into the reservoir which either self-ignites or is ignited, depending on reservoir temperature and composition. Heat and gases from the combustion pressurize the reservoir, and decrease viscosity both by heating and cracking. Often water is injected behind the fire front.

Steam Stimulation

(i) Existent Practice

Steam stimulation, by its very nature, is a limited process. After several cycles (perhaps over two to three years), the area in the immediate vicinity of a well has been flushed out and the wells fail to respond to further stimulation. It is rarely possible to recover more than 10% of the original oil-in-place via steam stimulation. Therefore, the real payoff via thermal methods will have to come from steam drive or combustion. However, steam stimulation is almost universally the first step in applying thermal measures to a field.

Steam stimulation projects (many of them dating back to the mid-sixties) are in place on 19 of the largest California fields. The average starting date of these projects was 1966. Even allowing for a period of field testing, most of them are well along toward completion. Of the 44 domestic steam stimulation projects listed as active by the Oil and Gas Journal in 1973, in 32 cases, the operator reported the project was at least half finished. Therefore, one suspects that much of this oil is already in the API reserves estimates, if, in fact, it has not already been produced.

(ii) Cost-Performance Characteristics

The Kern River field produces 12° to 16° gravity oil from 500 to 1300 feet depths. Original oil-in-place is about four billion barrels. This field has been the subject of more steam stimulation and steam drive investment than any other field in the country. Over 2500 wells have been subject to steam stimulation. In 1970 after some five years of pilot tests the principal operator in the field, Getty estimated the ultimate recovery including complete steam drive at 1.4 billion barrels. The current OGJ estimate of the ultimate recovery from this field is 1.5 billion barrels. Clearly, the OGJ estimates includes not only steam stimulation but also projected steam drive oil. Thus, it is difficult to separate the recovery contribution of steam stimulation alone.

The OGJ ultimate for this field was increased by about 450 million barrels between January 1974 and January 1975. In the year before, it was increased by 50 million barrels. Once again, under the assumption that the Oil and Gas Journal and API estimates are similar, it appears that the lag between the decision to implement an enhanced recovery project and the appearance of the projected incremental recovery in the API reserves estimates is at most one or two years.

(iii) Future Recovery Prospects

Steam stimulation suffers from the same problem as waterflood with respect to the likelihood of the recent crude price rise adding significant new volume to reserves. That it was economically attractive at pre-1973 crude prices is clearly indicated by the average age of the steam stimulation projects. The Interstate Oil Compact Commission cites cost figures of $0.30 to $1.35 per barrel produced.[21] Geffen claimes $0.75 to $1.25.[13] As we shall see in the following discussion of steam drive, these are not economically unreasonable numbers at pre-1973 crude prices. Finally, steam stimulation like thermal methods, in general, is basically limited to shallow fields. Close well spacings are required and well costs rise rapidly with depth as do injection pressures. Much more importantly, however, the natural temperature gradient generally makes steam stimulation superfluous at depths of more than three or four thousand feet. To put it another way, highly viscous "heavy oil" is only found at shallow depths.[1] Therefore, if one accepts the arguments in Chapter II, we are unlikely to find much oil in the future in non-frontier areas to which we can usefully apply steam stimulation.

Steam Drive

(i) Existent Practice

At present, not counting pilot projects, steam drives are in place in the fields indicated in Figure IV-6.

(ii) Cost-Performance Characteristics

As indicated earlier, the principal aim of thermal methods is a decrease in viscosity. Figure IV-7 indicates the effect of

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[1] One important exception is portions of the Venezuela heavy oil belt.

FIGURE IV - 6

SUMMARY OF ACTIVE STEAM DRIVE PROJECTS

Field[1]	Year Initiated[2]	OOIP (MMBLS)	Cum. Prod.as of 1/1/75 (MMBLS)
Kern River	1964	4000	636
Midway Summit	1967	6000[3]	1197
S. Belridge	1970	1000[3]	195
San Ardo	1963	1500	274
Huntington Beach	1965	6000	923
Yorba Linda	1964	100	30
Smackover[4]	1971	1500	508
Winklemann Dome[5]	1964	100[3]	

Notes:

[1] All Fields shown are in California unless otherwise noted.

[2] Generally refers to start of pilot, not start of field wide project.

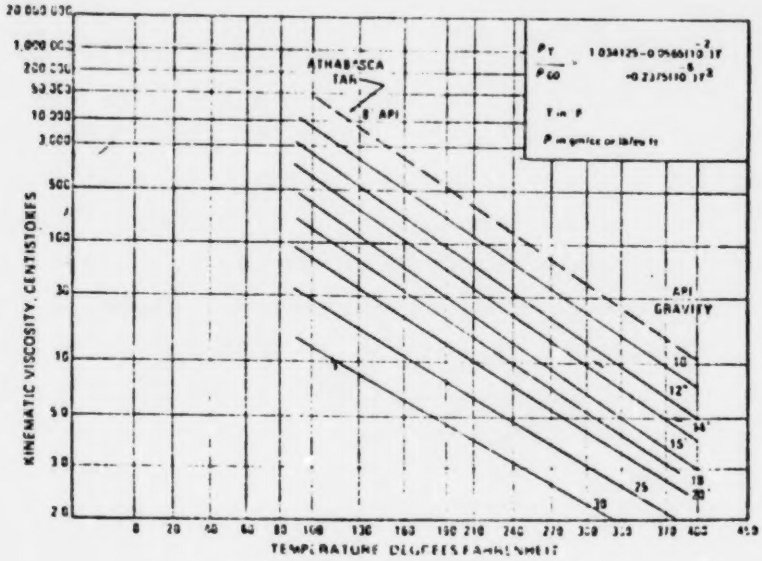
[3] Estimated volumes.

[4] Located in Arkansas.

[5] Located in Wyoming.

FIGURE IV - 7

TEMPERATURE EFFECTS ON OIL VISCOSITY AS A FUNCTION OF OIL GRAVITY



Source: Reference [21]

temperature on oil viscosity as a function of API gravity. Increasing the temperature of a 15° API crude from roughly 90° to 300° will result in a reservoir fluid which has about the same viscosity as a 30° API oil in a shallow reservoir. In order to obtain this increase, operators have reported steam/oil ratios ranging between 3 to 10. It takes about 1 barrel of fuel to produce 15 barrels of 70% quality saturated steam at 200 psi surface.

The fuel used in these projects is generally lease crude or topped lease crude although in some cases residual oil is used. In any case, the cost to the nation of this fuel is about $10.00 per barrel or 67¢ per barrel of steam. To this must be added the cost of the steam generator. A 50 MMBTU/HR steam generator capabile of producing 700,000 barrels of steam per year currently costs about $250,000 delivered. Assuming a ten year life and a 10% cost of capital this works out to 6¢ per barrel of steam. SOCAL reports maintenance costs of 5¢ to 8¢ per barrel of steam. The water reclamation plant at Kern River constructed at a cost of 1.7 million dollars can reclaim 75,000 bbls of water per day or about 2¢ per barrel. Smaller treatment plants might have a cost of 5¢ per barrel. In total, then, steam might cost about 85¢ per barrel. Adding normal waterflood lifting costs (well workover, pumping, well maintenance, fluid distribtuion, etc) of $0.50 to $1.5 0 per barrel of crude produced, leads to the aggregate costs shown in Figure IV-8.

Figure IV-8 illustrates the obvious point that steam drive is energy intensive and as such has not been helped all that much by the rise in crude prices. According to these numbers a tripling in crude price raises the breakeven steam/oil ratio from about 5:1 to about 10:1. All the operators interviewed indicated they

FIGURE IV - 8

STEAM DRIVE COST PER BARREL OF RECOVERED CRUDE AS FUNCTION OF STEAM OIL RATIO

(all values $/bbl)

	Non-Steam Related Costs	Steam-Oil Ratio			
		3	5	7	10
$3.00/BBL Fuel Cost	0.50	1.70	2.50	3.20	4.50
	1.00	2.20	3.00	3.70	5.00
	1.50	2.70	3.50	4.20	5.50
$10.00/BBL Fuel Cost	0.50	3.05	4.75	6.45	9.00
	1.00	3.55	5.25	6.95	9.50
	1.50	4.05	5.75	7.45	10.00

expected average steam/oil ratios of less than 5:1, which is consistent with the fact that the projects were either underway or at least being seriously considered before the price rise. Furthermore, they expected these projects to allow the fields to reach ultimate recoveries of 45-50% of original oil-in-place.

This brings us to another important problem in steam drive projects. Once such a drive is in full operation and has raised the temperature of the reservoir fluid, one faces the same non-linear physics of a waterflood with the exception that the 'water' is more expensive and the mobility ratio even more unfavorable. That is, the relative permeability of the reservoir to oil drops as the steam/water saturation increases. Water/oil ratios at producing wells increase sharply and beyond a point the additional oil produced per additional unit of injected fluids drops off sharply. Most of the oil produced by steam floods will be produced at low steam/oil ratios. Moreover, the additional oil which can be produced at higher steam/oil ratios is quite marginal and falls off sharply as this ratio increases.

(iii) Future Recovery Prospects

The effect of this sharp rise in marginal cost, combined with the fact that the injection fluid is much more expensive than water (particularly energy-wise), indicates that even significant increases in crude price beyond the present cost of crude will be able to generate very little additional steam drive oil above that which would come out at steam/oil ratios of about 5:1. Once again the supply curve appears to become very steep much beyond a price of roughly $5.00-$6.00 per barrel.

The analysis of Chapter III indicates that there is perhaps 40 billion barrels of oil remaining in already discovered reservoirs which meet the requirements of steam drive (i.e. low API gravity, high permeability, shallow depth, etc.). On average, these reservoirs have already produced about 20% of the original oil-in-place. Assuming all these fields can be made to produce 50% of their oil, this leaves some 12 billion barrels still to be recovered. The current OGJ reserves for these fields are listed at about 2 billion barrels.

In summary, then, we feel that steam drive at present prices may add as much as 10 billion barrels to reserves. Further, the avearage cost to the nation of much of this oil may be less than $5.00-$6.00. Hence the production of this oil represents a significant increase in national income over imported crude at current prices. However, by the same token, the supply curve appears quite steep in the range of $6.00 to considerably higher-than-present prices. We think it likely that about the same amount of steam drive oil will be produced at $6.00 per barrel as would at $12.00 per barrel, though the higher prices could extend the economic life of specific existent projects.

In-Situ Combustion

(i) Existent Practice

There have not yet been as many in-situ combustion projects initiated in comparison to steam flood. However, the combustion projects attempted have covered fields exhibiting a wider range of API gravities, depths, and permeabilities than with steam flood. Almost all of these projects though, have been begun on a pilot test basis.

In-situ combustion is undoubtedly the most difficult of the tertiary processes to model and predict. Also, it is the one method on which we were able to obtain the least reliable data. Published reports are conflicting and non-committal. However, in very general terms, the economics of combustion are not all that different from that of steam drive. In-situ combustion involves the maintenance of an ignited flame front in the reservoir fed by the reservoir crude, itself. The "fuel" for this method then is essentially a free good since not only is no out-of-pocket cost incurred with its use, but also there exists no alternative opportunity cost for the consumed crude. Some of this advantage is lost, however, in the fact that the injection air (about 11,000 standard cubic feet/barrel burned) must be compressed. Also the high temperatures at the fire front lead to greater losses to the formation. This is generally countered by injecting water either simultaneously with the air or afterwards, thereby transferring heat from the formation back to the driving fluid.

(ii) Cost-Performance Characteristics

Some problems have been encountered with respect to combustion sweep efficiencies. One of the largest pilots was that conducted by Amoco over the greater part of the 39° API Sloss Field in Nebraska[22]. This operation reported a volumetric sweep efficiency of only 14%. The project (now concluded) recovered about 0.8 million of the 5.9 million barrels remaining after waterflood. The residual oil saturation at the beginning of this project was only 30%.

Conversely, firefloods in Venezuela have been applied to hardly depleted, deep, thick, permeable, heavy oil reservoirs and quote target recoveries of about 50%. In these instances, the fireflood is operating in much the same fashion as a steam drive. Although we have not been able to obtain reliable data to substantiate the effectiveness of the method, it appears that fireflood has an advantage over steam drive as heavy oil reservoirs get deeper. Certainly, fireflood cannot be used in very shallow reservoirs for the pressures generated would blow through the overburden.

(iii) Future Recovery Prospects

From the point of view of projecting domestic supply from heavy oil reservoirs, with the exception of extremely shallow deposits, both steam drive and fireflood are going after the same type of low API gravity oil. Thus, despite their relative economics, it would be "double counting" to credit the recovery potential for these heavy oil deposits to each of these thermal methods separately.

The use of firefloods on lighter crudes in previously waterflooded reservoirs is a bit different situation. Most of these projects have been discontinued,but it is a potential means of going after truly tertiary oil. Given the current lack of combustion activity in this area relative to that for CO_2 and micellar, we suspect its economics are less favorable than those of these miscible methods. If so, even at present prices, combustion would not make a significant contribution to supply from medium to light oil reservoirs. At present, without the necessary data to perform an adequate assessment, we can only speculate as to how large this contribution might be.

Heavy Oil Sands: Role of Experimental Recovery Methods

(i) Existent Practice

There is one possible source of heavy oil which does not show up in the list of major reservoirs discussed in Chapter III. The deposits of shallow viscous oil in the northeastern Oklahoma-Missouri-Kansas border area have estimated amounts of oil-in-place which range from a few billion barrels to more than 50 billion barrels.[23] There has been essentially no recovery from these deposits and Bureau of Mines personnel claim they do not show up in any published estimate, of domestic oil in place with the exception of B.O.M.'s own heavy oil report.[24]

(ii) Cost-Performance Characteristics

Most of this oil is extremely shallow, 400' or less. The important difference between this oil and the shallow heavy oil in California fields is permeability. The California fields tend to have permeabilities in the range of 1000 to 10,000 millidarcies. The Missouri deposits have permeabilities in the range of 100 to 200 millidarcies or less.

The thermal methods described earlier are dependent on a combination of permeability, thickness, and viscosity such that steam (air) can be injected into the formations. In California this is generally possible. In the Missouri-Kansas deposits, however, attempts to inject air for in-situ combustion, and steam for steam drive, have required pressures which have blown through the overburden. Harvey and Arnold[23] indicate that reservoirs whose combination of permeability, viscosity and depth make injection for steam flooding and combustion impossible cannot be produced profitably by such techniques as "reverse combustion" (analogous to steam stimulation only using combustion). Their economic calculations indicate break-even prices of $25.00 per barrel or more for typical Kansas-Missouri heavy oil parameters.

The B.O.M. personnel at Bartlesville are taking a different approach. It involves close well spacing, establishing communication between wells by explosive fractioning, and the injection of a heated solvent (esentially benzene) whose sole purpose is to lower the viscosity of the crude. A soak period is then followed by a water or steam flood. The produced solvent is then recovered and reinjected.

This method is in a very preliminary pilot stage, and thus far overall recoveries do not appear too good, averaging about 10% for a 50% pore volume slug of solvent. At these recovery rates, and with solvent costs at 30¢ per gallon, solvent recovery is a must. Performance results on solvent recovery are not yet available. To the solvent costs we must add both (a) the drilling of closely spaced wells and (b) the costs of fractionating.[1]

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[1] B.O.M. used 900 lbs of TNT at 28¢/lb in their pilot.[25]

(iii) Future Recovery Prospects

At present, the outlook is somewhat dim for solvent extraction methods unless a breakthrough in solvent recovery is obtained. In short, it does not appear that the Missouri-Kansas heavy oil sands will be a significant part of domestic supply of conventional oil unless prices rise considerably above current levels to well above $15.00 per barrel. For reservoirs like these we are almost in an oil shale situation. Indeed, there has even been some discussion of strip mining these deposits.

V. SUMMARY AND CONCLUSIONS

Recall that in Chapter II we indicated that the level of new discoveries in frontier areas is essentially a speculative variable which can conceivably range from nil to in excess of 200 billion barrels. The median estimates, however, are in the neighborhood of 70 to 100 billion barrels. The results of Chapter II also indicate that most of whatever oil is found will be discovered in large fields, and thus the unit resource cost of most of this oil will be considerably below present market prices. We are not optimistic about the quantities of new discoveries to be found in non-frontier areas. We believe they are likely to be an order of magnitude smaller than the frontier area discoveries. In fact our feeling is that future onshore Lower 48 discoveries may prove quite small, indeed.

To attempt to place precise bounds on the potential recovery volumes associated with these inordinately gross estimates of yet-to-be-discovered oil is at best an academic exercise. Let us then confine the remainder of our comments to the primary goal of this study which is to assess the enhanced recovery prospects for already discovered oil associated with a variety of secondary and tertiary recovery methods.

Impacts Upon Increased Ultimate Recovery

In each of the sections of Chapter IV which discussed specific recovery techniques, a summary subsection was included which assessed, albeit sometimes qualitatively, the future recovery prospects associated with the particular method described in the immediately preceding subsections. Figure V-1 further recapitulates these summaries as to our best estimates of incremental enhanced recovery for already discovered remaining oil-in-place as of 12-31-74.

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FIGURE V - 1

PRELIMINARY ESTIMATES OF INCREMENTAL ENHANCED RECOVERY OF REMAINING OIL-IN-PLACE AS OF 12-31-74*

Method of Recovery	Low Range** Estimate (10^9 BBLS)	High Range*** Estimate (10^9 BBLS)
Extended Waterflood	*8.00*	*9.00*
Thermal (primarily steam, cyclic and flood)	*4.25*	*9.75*
Micellar and hydrocarbon miscible	*0.25*	*2.50*
CO_2 and inert gas miscible	*2.50*	*3.75*
TOTAL	*15.00*	*25.00*

*assumes lifting of current two-tier FEA "old-new" price regulation; otherwise assumes existing tax and cost treatment policies.

**free market prices in $8-12 range.

***free market prices in $12-16 range.

In order to put these estimates in perspective, it is quite useful to compare our estimates with those recently presented by the Interstate Oil Compact Commission based upon contract research completed for the Federal Energy Administration in early 1975.

During the period of December 1974 through January 1975, the Interstate Oil Compact Commission and the regulatory bodies of the compacting states collected a comprehensive data base on existing and projected enhanced recovery activities. Responses were received from over 900 operators of enhanced recovery projects in 30 compacting states, with individual data collected on over 4300 existing projects.

These responses represented over 49% of the 1973 domestic enhanced production. On a state-by-state basis, statistically valid responses were received from 28 of the 30 compacting states. These twenty-eight states produced more than 98% of the crude oil recovered by existing enhanced recovery projects in 1973.

The data collected by the Interstate Oil Compact Commission and the compacting states' regulatory bodies was compiled into a computer data base. This information was projected on a state-by-state basis, based on the percentage of 1973 enhanced production represented by the respondent replies for that state.

Figures V-2 and V-3 illustrate the composition of the 1973 domestic crude oil production, including the contribution from enhanced recovery projects as regulated under the prevailing FEA "two-tier" price control policy. Figure V-4 shows the estimated composition of enhanced recovery production for 1974 between "controlled" and "free market volumes."

In 1973, the United States total average daily crude oil production was approximately 9.2 million barrels per day. Of this, approximately 41 percent or 3.8 million barrels per day was produced by enhanced recovery methods. Of the

FIGURE V - 2

SUMMARY OF 1973 DOMESTIC CRUDE OIL PRODUCTION

CONTRIBUTION OF ENHANCED RECOVERY PROJECTS

State	Daily Average Production (BBLS/Day)	Daily Average Enhanced Production (BBLS/Day)	% Of Daily Average Production Produced By Enhanced Recovery Methods	Daily Average Stripper Production[1] (BBLS/Day)	% Of Stripper Production Produced By Enhanced Recovery Methods	Daily Average Stripper Enhanced Recovery Production (BBLS/Day)	Daily Average Non-Stripper Enhanced Recovery Production (BBLS/Day)
Alabama	31,992	15,488	49.03	126	-0-	-0-	15,488
Alaska	198,145	193,745	97.78	-0-	NA	-0-	193,745
Arizona	2,202	-0-	NA	-0-	NA	-0-	-0-
Arkansas	49,359	12,721	25.77	18,244	20.91	3,814	8,907
California	920,753	395,233[2]	42.92	168,362	40.00	67,343	327,890
Colorado	100,247	68,649	68.48	5,260	21.88	1,150	67,499
Florida	89,575	1,652	1.84	-0-	-0-	-0-	1,652
Illinois	84,025	60,140	71.57	78,978	75.73	59,808	332
Indiana	14,553	7,258	49.87	14,395	49.85	7,176	82
Kansas	181,443	58,523	32.25	125,888	39.82	50,126	8,397
Kentucky	23,800	20,222	84.97	20,038	83.26	16,685	3,537
Louisiana	2,278,148	354,992	15.58	20,068	56.00	11,238	343,754
Michigan	40,038	6,641	16.59	13,323	49.84	6,641	-0-
Mississippi	153,704	28,236	18.37	1,200	17.12	206	28,030
Missouri	164	74	45.00	164	44.92	74	-0-
Montana	94,849	73,019	76.98	5,873	13.06	767	72,252
Nebraska	19,836	8,926	45.00	3,277	32.71	1,072	7,854
Nevada	263	-0-	NA	-0-	NA	-0-	-0-
New Mexico	276,674	76,381	27.61	28,011	28.91	8,096	68,285
New York	2,649	2,258	85.21	2,655	85.00	2,258	-0-
North Dakota	55,438	31,874	57.49	2,340	50.84	1,189	30,635
Ohio	24,099	244	1.01	16,868	1.45	244	-0-
Oklahoma	523,847	328,436	62.7	203,041	64.67	131,315	197,121
Pennsylvania	8,992	4,732	52.62	8,992	52.62	4,732	-0-
South Dakota	753	-0-	NA	74	-0-	-0-	-0-
Tennessee	550	-0-	NA	123	-0-	-0-	-0-
Texas	3,547,044	1,829,008	51.56	307,526	32.00	98,411	1,730,597
Utah	89,468	41,515	46.40	362	-0-	-0-	41,515
West Virginia	6,534	1,318	20.17	6,595	20.00	1,318	-0-
Wyoming	388,805	155,521	40.00	4,890	52.20	2,554	152,967
TOTAL	9,207,949	3,776,806	41.02	1,056,673	45.07	476,217	3,300,589

[1] National Stripper Well Survey, January 1, 1974, Interstate Oil Compact Commission

[2] 144,800 BPD by Cyclic or Flood Steam Injection.

FIGURE V - 3

SUMMARY OF 1973 AVERAGE ENHANCED PRODUCTION RATES BY STATE CONTROLLED AND FREE MARKET VOLUMES

State	Daily Average 1973 Enhanced Production (BBLS/Day)	Daily Average Free Market Stripper (BBLS/Day)	Daily Average Free Market Other (BBLS/Day)	Daily Average "Controlled" (BBLS/Day)
Alabama	15,488	-0-	-0-	15,488
Alaska	193,745	-0-	13,562	180,183
Arizona	-0-	-0-	-0-	-0-
Arkansas	12,721	3,814	3,296	5,611
California	395,233	67,343	74,794	253,096
Colorado	68,649	1,150	15,526	51,973
Florida	1,652	-0-	33	1,619
Illinois	60,140	59,808	332	-0-
Indiana	7,258	7,176	3	79
Kansas	58,523	50,126	2,518	5,879
Kentucky	20,222	16,685	2,299	1,238
Louisiana	354,992	11,238	61,877	281,877
Michigan	6,641	6,641	-0-	-0-
Mississippi	28,236	206	8,129	19,901
Missouri	74	74	-0-	-0-
Montana	73,019	767	2,167	70,085
Nebraska	8,926	1,072	2,512	5,342
Nevada	-0-	-0-	-0-	-0-
New Mexico	76,381	8,096	22,534	45,751
New York	2,258	2,258	-0-	-0-
North Dakota	31,874	1,189	8,285	22,400
Ohio	244	244	-0-	-0-
Oklahoma	328,436	131,315	74,907	122,214
Pennsylvania	4,732	4,732	-0-	-0-
South Dakota	-0-	-0-	-0-	-0-
Tennessee	-0-	-0-	-0-	-0-
Texas	1,829,008	98,411	571,589	1,159,008
Utah	41,515	-0-	9,964	31,551
West Virginia	1,318	1,318	-0-	-0-
Wyoming	155,521	2,554	61,186	91,781
TOTAL	3,776,806	476,217	935,513	2,365,076

Source: Interstate Oil Compact Commission. Based on best available data from individual state regulatory agencies in November 1974. Most projections are based on 1973 and 1974 production data and September through November 1974 pricing information.

FIGURE V - 4

ESTIMATES OF 1974 AVERAGE ENHANCED PRODUCTION RATES BY STATE

CONTROLLED AND FREE MARKET VOLUMES

State	Daily Average Production (BBLS/Day)	"Controlled" (BBLS/Day)	"Free Market" (BBLS/Day)	Estimated 1974 Total Enhanced Production (BBLS/Day)
Alabama	32,310	15,340	300	15,640
Alaska	192,180	181,750	10,430	192,180
Arizona	1,960	-0-	-0-	-0-
Arkansas	45,810	5,200	6,600	11,800
California	883,750	242,920	136,430	379,350
Colorado	105,710	52,030	16,620	68,650
Florida	99,850	1,620	7,740	9,360
Illinois	76,950	-0-	55,080	55,080
Indiana	13,450	410	6,300	6,710
Kansas	167,440	5,430	48,580	54,010
Kentucky	21,460	1,120	17,120	18,240
Louisiana	2,078,630	257,190	66,710	323,900
Michigan	47,960	-0-	6,700	6,700
Mississippi	140,150	18,150	7,600	25,750
Missouri	160	-0-	70	70
Montana	96,880	68,410	6,180	74,590
Nebraska	17,890	4,800	3,250	8,050
Nevada	349	-0-	-0-	-0-
New Mexico	265,470	43,900	29,390	73,290
New York	2,700	-0-	2,300	2,300
North Dakota	54,500	22,040	9,300	31,340
Ohio	26,331	-0-	270	270
Oklahoma	487,510	113,730	191,920	305,650
Pennsylvania	9,500	-0-	5,000	5,000
South Dakota	1,560	-0-	-0-	-0-
Tennessee	352	-0-	-0-	-0-
Texas	3,474,660	1,230,000	670,000	1,900,000
Utah	115,530	28,030	18,700	46,730
West Virginia	7,370	-0-	1,200	1,200
Wyoming	399,490	87,450	72,340	159,790
Total	8,867,862	2,379,520	1,396,130	3,775,650

Source: Interstate Oil Compact Commission

3.8 million barrels per day from enhanced production projects, approximately 13 percent or 476 thousand barrels per day was produced from projects whose average daily production per well was less than 10 barrels. Individual wells producing at this rate are classified as "stripper wells." Approximately 63 percent of this enhanced recovery production, or 2.36 million barrels per day, is classified as "old oil" under the FEA two-tiered price controls.

The IOCC also estimates that about 14.6 billion barrels of recoverable oil remained, as of December 31, 1974, as proven reserves in existing enhanced recovery projects. This compares with proven remaining reserves of 9.6 billion barrels attributed to Alaska's North Slope. Recall that in our earlier assessments of the incremental ultimate recovery attributable to the various recovery methods, we could only speculate as to how much of our additional recovery estimate for each method was already contained in the API figures:

If one considers that:

- From August 1973 to the present the selling price of all crude oil produced in the United States has been subject to either control by the Federal government or specifically exempt from such control; and that
- Production which is exempt is sold at a free market price ranging from $8 to $12 per barrel; production which is subject to control is sold at a price of $5.25 per barrel;

then, the following conclusion may be made. Our "low end" estimates of enhanced recovery potential from already discovered oil are almost identical with IOCC's quoted figure of 14.6 billion barrels. While we are not given a disaggregation of this recovery by method to make a direct comparison with our estimates, we do know the following. The IOCC estimated that there are approximately 9,000 existing enhanced recovery projects.[1] They have over 125 thousand producing wells and an estimated 14.6 billion barrels of proven recoverable oil remaining as of December 31, 1974. Of this 14.6 billion barrels of recoverable oil remaining, approximately 79 percent is associated with pressure maintenance, waterflooding and cyclic steam injection projects. The remaining 21 percent is associated with other "more exotic" enhanced recovery projects. By comparison, our estimates of extended waterflood and thermal combined (12.25 out of 15.00 billion barrels) is roughly 82% of our total projected recovery. When our figures are adjusted downward for steam drive (the IOCC 79% includes only "huff and puff") we are probably 3-4% below the IOCC estimates.

Perhaps the closest direct inference we can make with regard to a supply curve of enhanced production through the early 1980s also stems from data produced by IOCC as part of its FEA study. Figure V-5 shows IOCC's estimate of projected capital investment and the number of additional new recovery projects for the next half-decade assuming:

- the end of two-tier controls and a prevailing free market price of $10/bbl (median of the $8-12 range)
- current expectations of "stable" costs and existent tax policies as each affect enhanced recovery.[2]

The IOCC estimates that between 1975 and 1980, approximately $6.9 billion will be invested in new and existing enhanced recovery projects if all oil produced from enhanced recovery were released from price controls.

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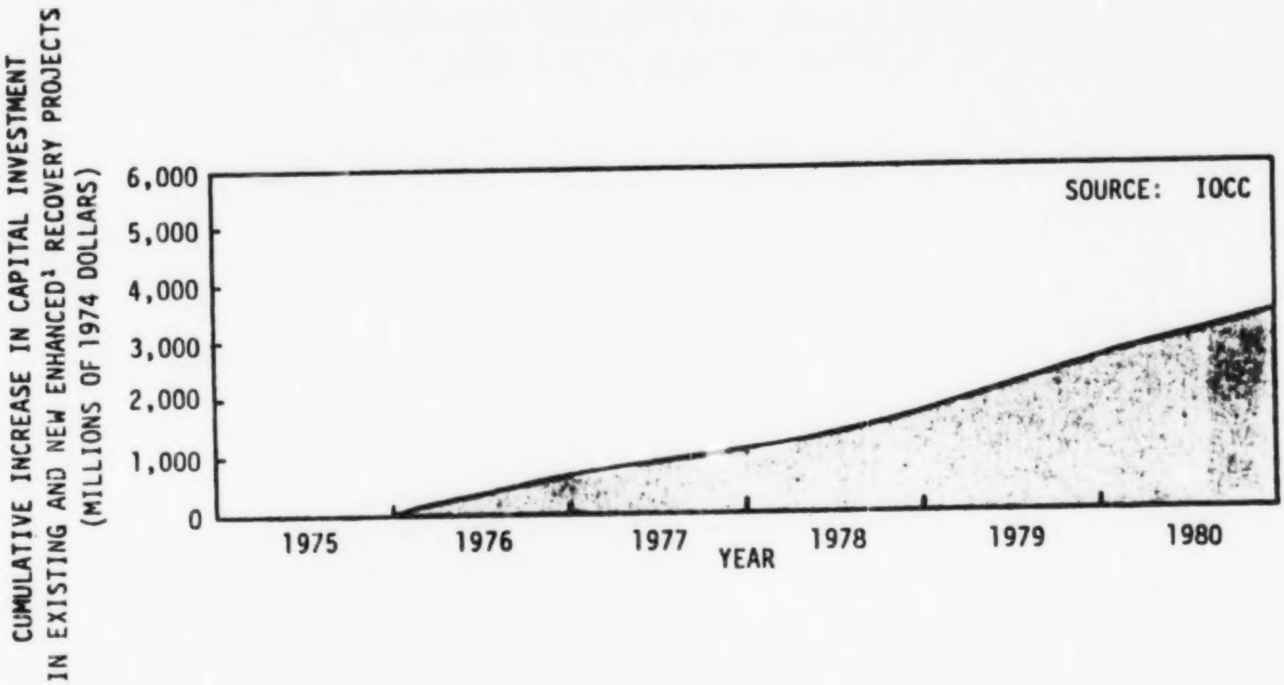
[1] Resource Analysis and Management Group analysis of data provided through the Interstate Oil Compact Commission.

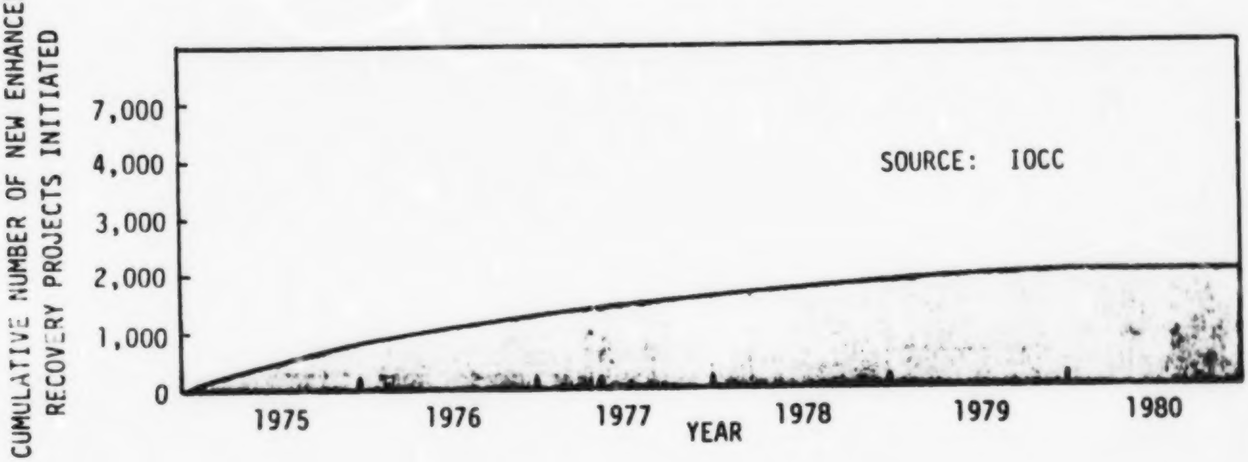
[2] No explicit assumptions regarding rates of inflation, etc., are presented.

FIGURE V - 5

PROJECTED ADDITIONAL CAPITAL INVESTMENT IN EXISTING AND NEW ENHANCED RECOVERY PROJECTS[1]: 1975 - 1980



PROJECTED ADDITIONAL NEW ENHANCED RECOVERY PROJECTS[1] INITIATED: 1975 - 1980



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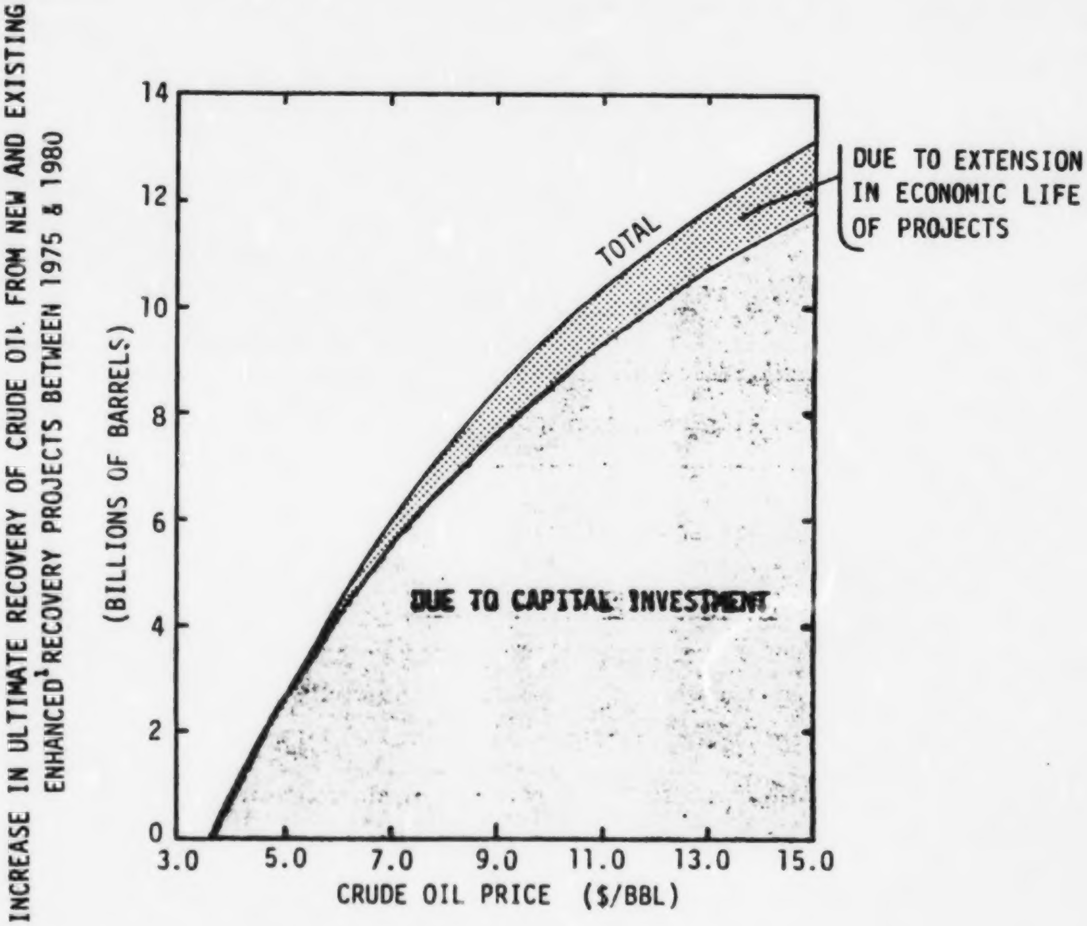
[1] Assumes the release of all production produced by enhanced recovery projects from price controls.

Source: Interstate Oil Compact Commission (FEA C-05-50130-00)

FIGURE V - 6

EFFECT OF CRUDE OIL PRICE ON ULTIMATE RECOVERY FROM EXISTING AND NEW ENHANCED RECOVERY PROJECTS INITIATED BETWEEN 1975 - 1980



[1] Assumes removal of two-tier price controls, stable rates of increase in recovery costs no greater than present rates and existent tax structures.

Source: Interstate Oil Compact Commission (FEA c-05-50130-00)

Of this $6.9 billion, approximately 50 percent or $3.4 billion is projected to be invested in projects made economical by decontrol of all production from enhanced recovery projects, the retention of the existing tax structure, and increase in other costs at a rate "less than recently experienced." During the 1975 to 1980 period, with decontrol, over four thousand (4,000) additional enhanced recovery projects are projected to be initiated. This is some two thousand (2,000) more projects than are projected to be initiated without decontrol. In each case, the other assumptions regarding cost projection and taxes are the same as stated above.

The increase in ultimate recovery of crude oil resources associated with enhanced recovery projects is affected by new capital investment in existing and new enhanced recovery projects. Also important in the increase are changes in the economic life of existing enhanced recovery projects.

The IOCC estimates that the increase in ultimate recovery of crude oil from new and existing enhanced recovery projects between 1975 and 1980, at a crude oil price of $10.00 per barrel, is approximately 10 billion barrels. Of this 10 billion barrels, approximately 10 percent comes from the extension in economic life of existing projects and 90 percent from capital investment in new and existing projects.

Figure V-6 shows the IOCC "supply curve" of enhanced recovery to ultimate proven reserves as a function of price. Notice that corresponding to our "high end" estimates (price range $12-16 per barrel), the IOCC curve would place incremental recovery volumes roughly between 11-13 billion barrels over and above the current 14.6 billion presently recoverable via enhanced methods.[1] Figures V-7 and V-8 indicate, at least for existent recovery projects, what effect increased price would have on increased ultimate recovery and economic project life for waterflood and "other" enhanced recovery methods. Thus it appears

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[1] Thus at a median price of $14/bbl, the IOCC estimate of total remaining recoverable volumes is roughly 26.5 billion bbls compared to our estimate of about 25 billion bbls.

FIGURE V - 7

INCREASE IN ULTIMATE RECOVERY OF CRUDE OIL DUE TO EXTENSION IN ECONOMIC LIFE OF EXISTING ENHANCED RECOVERY[1] PROJECTS*

		INCREASE IN ULTIMATE RECOVERY		
CRUDE OIL PRICE $/BBL	REVENUE TO[2] OPERATOR PER BBL OF PRODUCTION $/BBL	WATERFLOOD ENHANCED[3,4] PRODUCTION PROJECTS MM BBLS	OTHER ENHANCED[3,5] PRODUCTION PROJECTS MM BBLS	ALL ENHANCED PROJECTS MM BBLS
5.25	4.20	-	-	-
6	4.80	145	53	198
7	5.60	301	118	419
8	6.40	427	156	583
9	7.20	534	196	730
10	8.00	623	228	851
11	8.80	698	255	953
12	9.60	765	280	1,045
13	10.40	824	302	1,126
14	11.20	878	322	1,200
15	12.00	923	333	1,261

*Overall Source: The Resource Analysis and Management Group Under Contract to The Interstate Oil Compact Commission.

Notes:

[1] "Enhanced Recovery" includes production of crude oil from reservoirs through actions taken to enhance primary reservoir drive, i.e., pressure maintenance, water flooding, etc.

[2] Based on the operator receiving 80% of all revenue from the sale of crude oil. From 100% of the revenue, approximately 6% is paid to states as a severance tax. From 94% of revenue, royalty owners receive, on the average, 15% and the operator 85% - 85% of 94% is 80%.

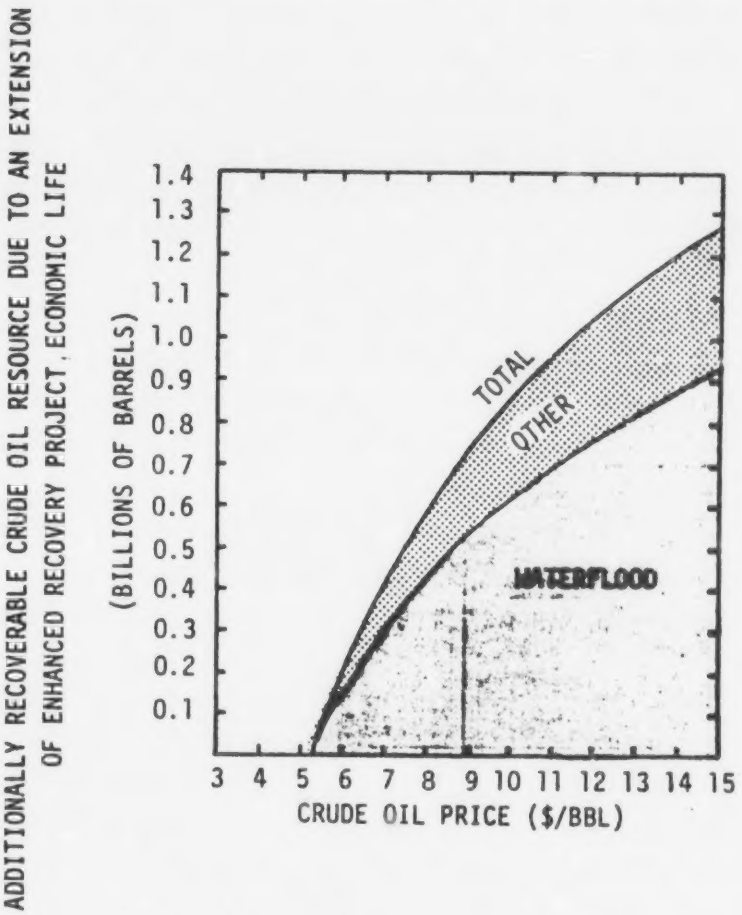
[3] *SOURCE:* Resource Analysis & Management Group analysis of data supplied by the Interstate Oil Compact Commission and State Regulatory Agencies.

[4] Based on 103,576 wells in existing waterflood enhanced recovery projects.
SOURCE: Data provided by the Interstate Oil Compact Commission and State Regulatory Agencies.

[5] Based on 27,793 wells in other enhanced recovery projects.
SOURCE: Data provided by the Interstate Oil Compact Commission and State Regulatory Agencies.

FIGURE V - 8

ADDITIONALLY RECOVERABLE CRUDE OIL FROM EXISTING ENHANCED RECOVERY PROJECTS DUE TO AN EXTENSION IN PROJECT ECONOMIC OPERATING LIFE AS A FUNCTION OF CRUDE OIL PRICE



Source: The Resource Analysis and Management Group; Data provided through the IOCC and State Regulatory Agencies.

that the IOCC in consonance with our earlier statements is also concluding that the supply curve is quite steep in the neighborhood of $10.00 per barrel and that even rather significant prices increases beyond $10.00 are unlikely to generate a lot more oil than that which would be produced at levels between $6-10 per barrel.

It is interesting that IOCC also concludes that due to project workovers and the new capital investment levels quoted earlier, even a free market price of no more than $10/bbl produces a jump in ultimate recovery by 1980 of almost a billion barrels. See Figure V-9. Thus, our "high end" estimate of 25 billion barrels is, as our earlier statements indicated, a reasonable expectation for free market prices in excess of $10/bbl.

Impacts on Crude Oil Production Rates

In translating this incremental increase in ultimate recovery into equivalent augmented daily production rates, again a comparison of our results with those of IOCC is most useful.

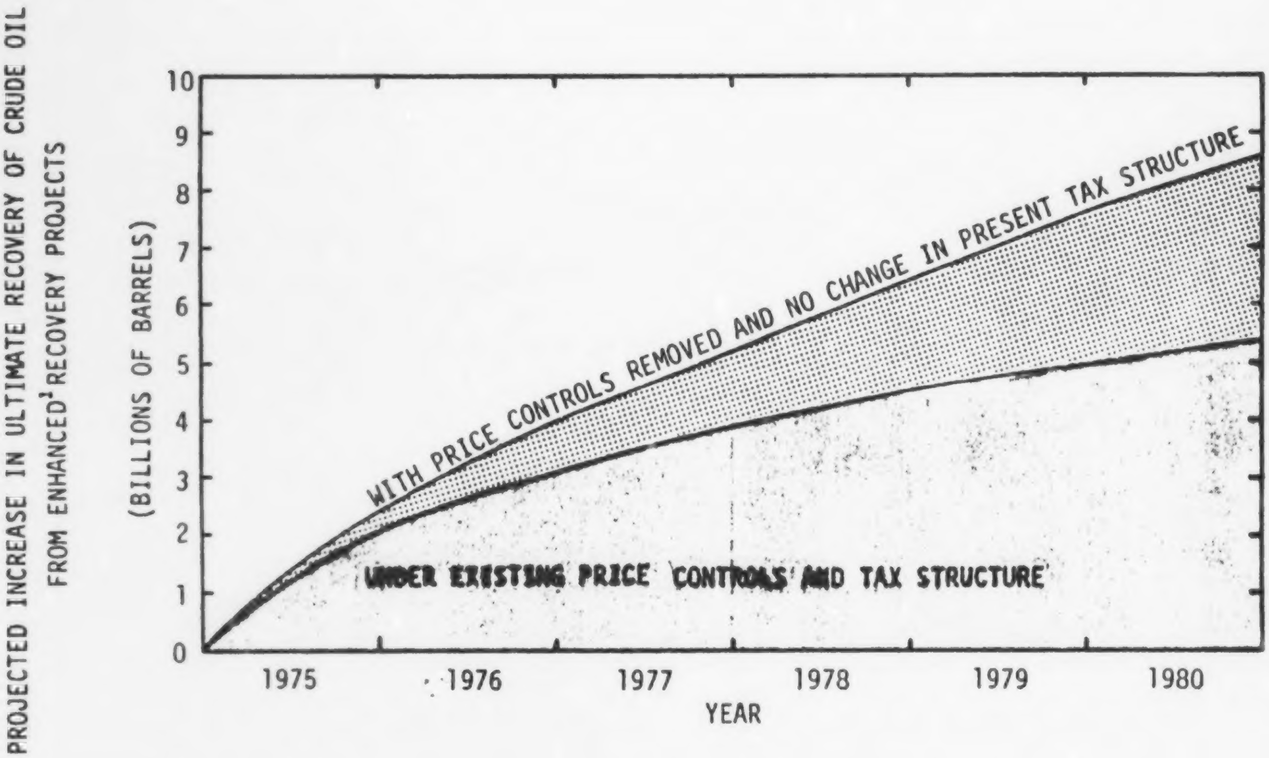
Figures V-10 and V-11 respectively, show the disaggregation of enhanced recovery daily production into the three components discussed above for both maintenance and removal of the two-tier price controls.

Figure V-12 shows in more detail, the contribution to daily enhanced recovery production rate from new deliverability from new projects, corresponding roughly to a 350,000 bbl/day augmentation. Figure V-13 shows the contribution to deliverability only from existent projects for which the indicated price increases would have the effect of extending their economic life.

These deliverability rates than would be consistent with our "high-end" estimate of 25 billion barrels of remaining recovery via enhanced methods beyond 1975, almost 15 billion of which is listed in proven reserves already.

FIGURE V - 9

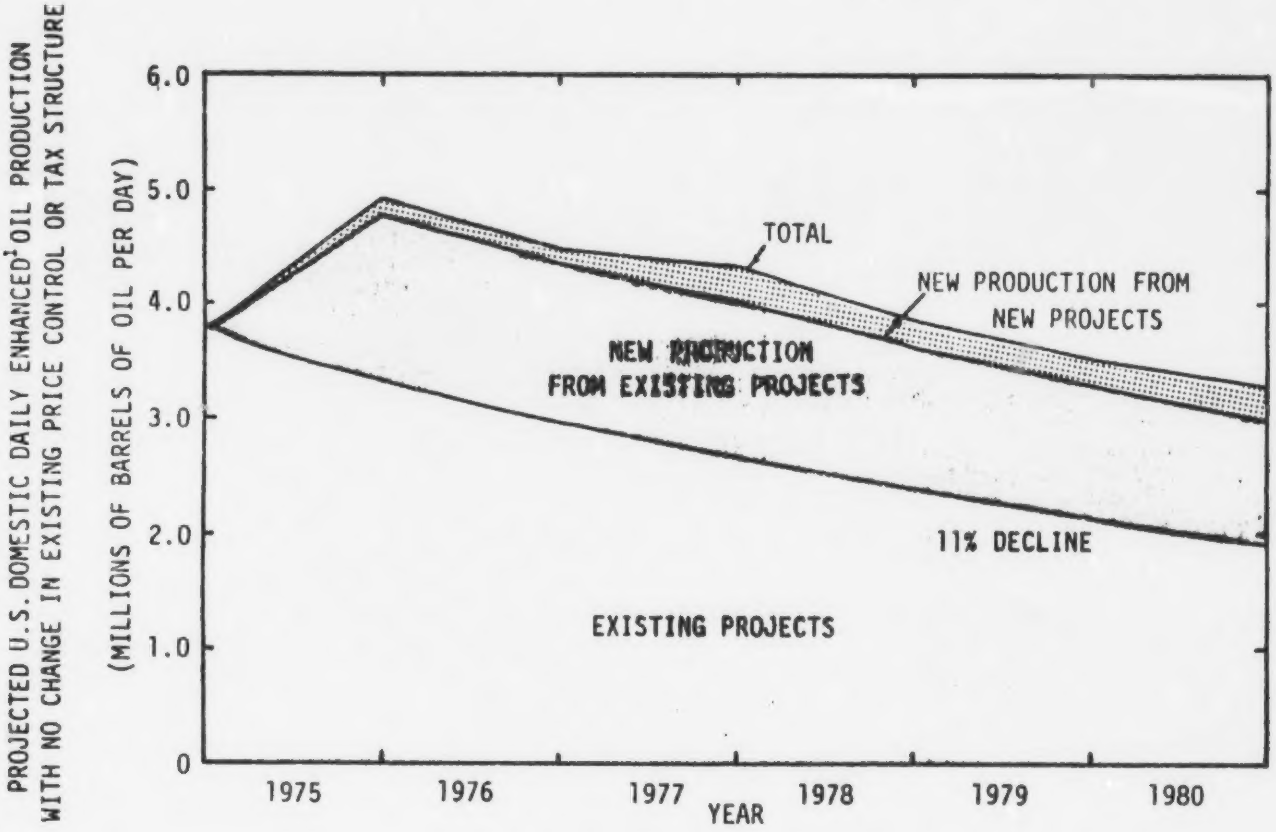
PROJECTED INCREASE IN ULTIMATE RECOVERY OF CRUDE OIL FROM EXISTING AND NEW ENHANCED RECOVERY PROJECTS DUE TO WORKOVERS AND NEW CAPITAL INVESTMENTS



Source: Interstate Oil Compact Commission (FEA C-05-50130-00)

FIGURE V - 10

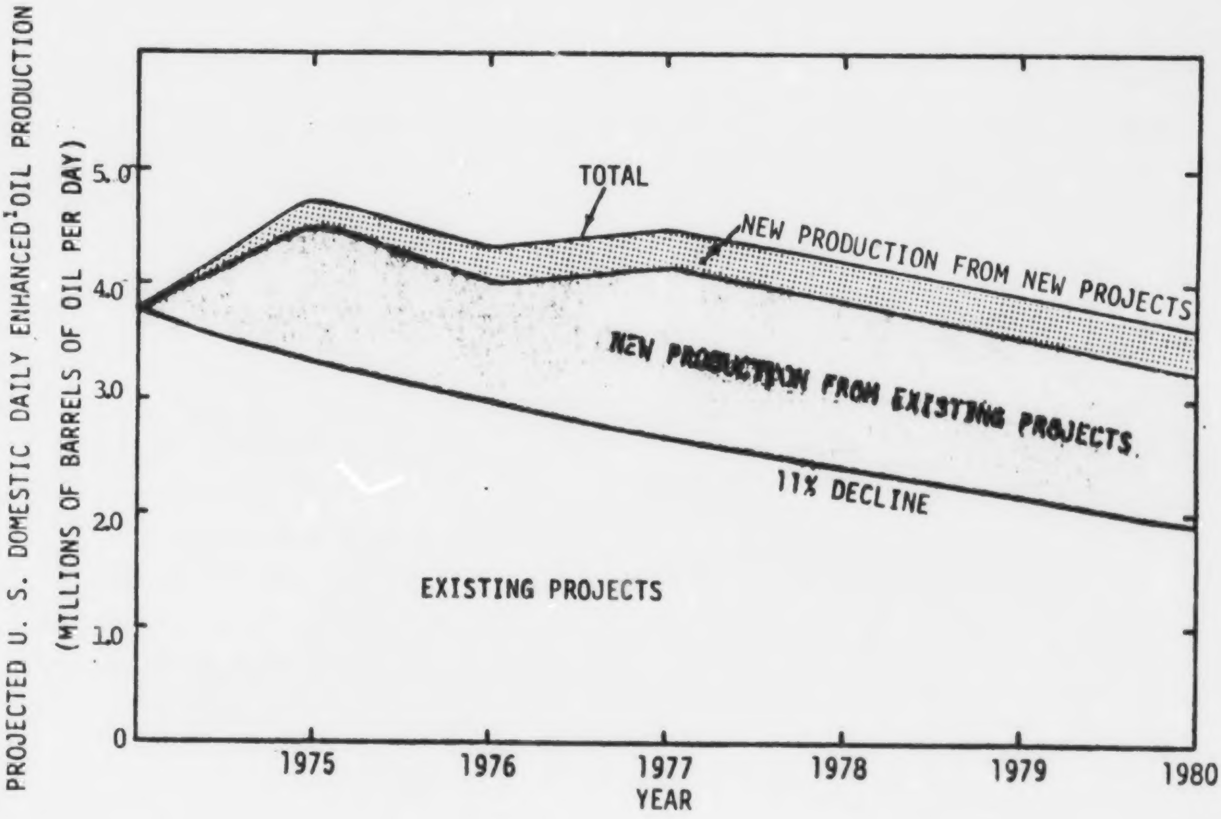
PROJECTED DOMESTIC ENHANCED PRODUCTION UNDER EXISTING PRICE CONTROL SYSTEM: NO CHANGE IN EXISTING TAX STRUCTURE



Source: Interstate Oil Compact Commission (FEA C-05-50130-00)

FIGURE V - 11

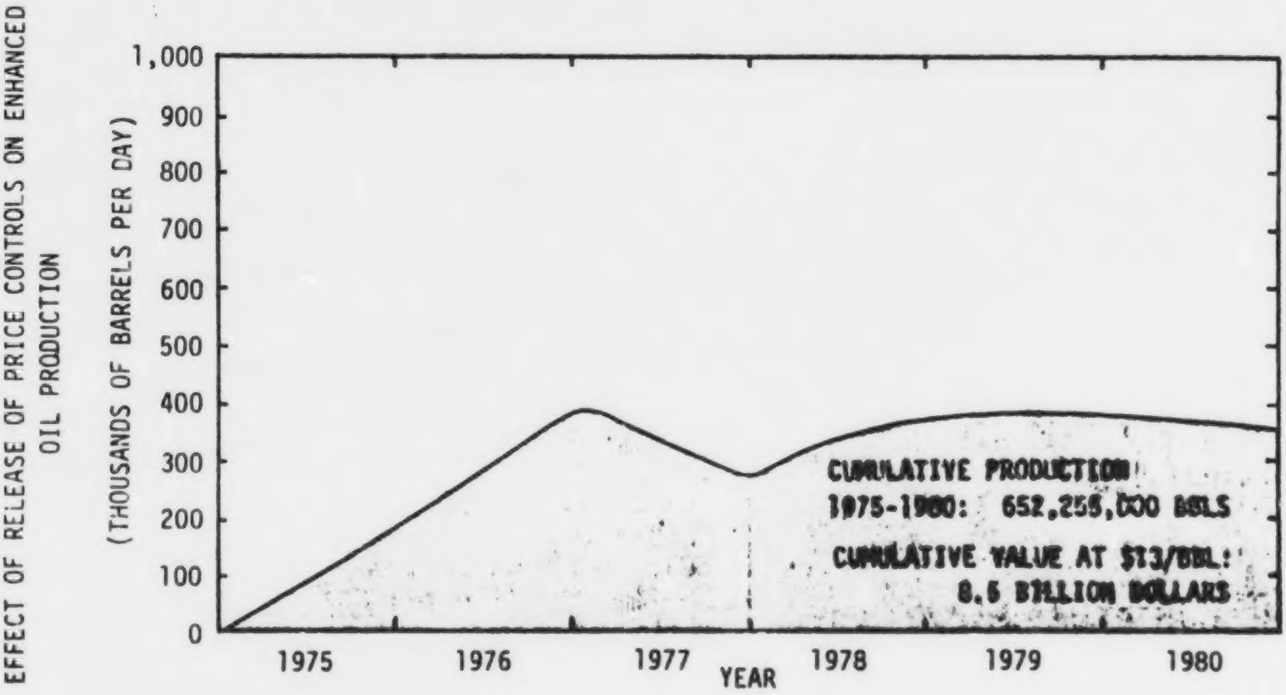
PROJECTED DOMESTIC ENHANCED PRODUCTION WITH PRICE CONTROLS REMOVED: NO CHANGE IN EXISTING TAX STRUCTURE



Source: Interstate Oil Compact Commission (FEA C-05-50130-00)

FIGURE V - 12

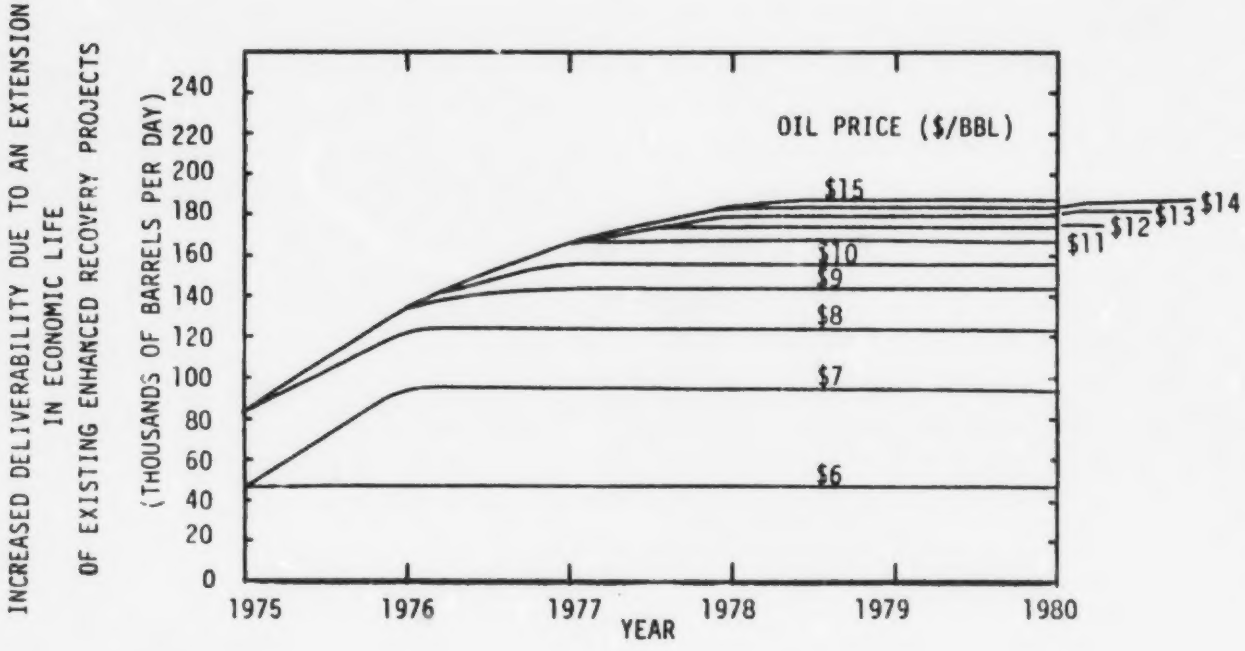
PROJECTED ADDITIONAL ENHANCED OIL PRODUCTION DUE TO RELEASE OF PRICE CONTROLS



Source: Interstate Oil Compact Commission (FEA C-05-50130-00)

FIGURE V - 13

PROJECTED INCREASE IN ENHANCED CRUDE OIL PRODUCTION DUE TO AN EXTENSION IN EXISTING PROJECT ECONOMIC LIFE*



* Note the highly dampened response above a free market price level of $10/bbl.

Source: The Resource Analysis and Management Group under contract to the Interstate Oil Compact Commission

Comparison With Project Independence Blueprint Assessment of Enhanced Recovery Potential

In its Project Independence Blueprint (PIB) effort[1], the Federal Energy Administration (FEA) essentially utilizes the methodology developed by the NPC [3] for its 1972 U.S. Energy Outlook: Oil and Gas Availability assessment to examine possible levels of future crude oil production.

Under its baseline or "business-as-usual" (BAU) scenario, FEA projects that at minimum acceptable prices of about $7 to $11 a barrel production would increase by 1980 to 11.1 to 12.2 million barrels a day respectively, and by 1985 to 11.9 to 15.1 million barrels a day exceeding the all time high production of 11.3 million barrels a day reached in 1970. The major sources of new crude oil (excluding NGL) in 1988 in excess of 1974 production under BAU assumptions at $11 per barrel would include:

	barrels per day
° Secondary production onshore	2,800,000
° Tertiary production onshore	2,650,000
° Alaskan North Slope	2,329,000
° Gulf of Mexico OCS	981,000
° California OCS	668,000
° Southern Alaska OCS	518,000
° Heavy crude oil and tar sands	440,000
° Atlantic OCS	110,000

Under its postulated "accelerated development" scenario, FEA projects that at minimum acceptable prices of $7 to $11 a barrel, production in 1980 would be 12.9 to 13.5 million barrels a day respectively, and in 1985, 16.9 to 20.0 million barrels a day, a range within which falls the 1974 consumption level of about 17 million barrels a day.

Tha major sources of further increase from "accelerated development" in production of crude oil in 1988 over the "business-as-usual" case would include:

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[1] Oil: Possible Levels of Future Production; Federal Energy Administration, Project Independence Blueprint Final Task Force Report; November, 1974

		barrels per day
°	Alaska North Slope	2,000,000
°	Tertiary recovery onshore	840,000
°	California OCS (including military)	832,000
°	Atlantic OCS	758,000
°	Southern Alaska OCS	504,000
°	Gulf of Mexico (including military)	404,000
°	Heavy crude oil and tar sands	300,000

Critical to these assumptions are that OCS leasing would be accelerated and that Naval Petroleum Reserve No. 4 would be opened for development and would be highly productive.

Figure V-14 shows the geographic disaggregations of Alaska and Lower 48 onshore and offshore areas into the NPC "petroleum provinces". Figures V-15 and V-16 show the judgemental appreciation factors applied to "new" (post-1970) and "old" (pre-1971) discovery values in order to derive increased recovery estimates as well as the improved constraints regarding absolute levels of total ultimate recovery. Figure V-17 shows the estimates of incremental cost per barrel produced via secondary and tertiary recovery derived by FEA as a result of the projected capital expenditures required for such projects.

Method-specific estimates of recovery potential are not given nor are separate estimates of primary, secondary and tertiary recovery given for all regions under the baseline scenario or its variations. However, Figure V-18 shows estimates for NPC Regions 5, 6 and 6-A of baseline recovery for selected years under alternative price assumptions as extracted from the PIB Final Task Force Report.[1] In short, neither the FEA PIB report nor, for that matter, the NPC Oil and Gas Availability assessment on which it is predicated are useful in providing clear insights on the factors which determine the viability of particular recovery methods in specific producing areas. Estimates of the potentials for improved recovery of oil originally in place were based primarily on the task force's judgements. The maximum average recovery assumed under the $7 BAU case is about 39 percent of the oil originally in place, compared to an average of about 31 percent at present. As an interesting aside, the FEA PIB report summarizes contemplated R&D expenditures for enhanced recovery programs as extracted form the Department of Interior's recent evaluation.[1] A total of $480 million is contemplated for improving oil and gas recovery, including $65 million for study and control of potential environmental effects of producing operations on the OCS and elsewhere. By far the largest portion of the total (more than $300 million) is directed to enhanced recovery. Among the tertiary recovery techniques to be investigated and developed are micellar-polymer flooding, and use of carbon dioxide produced as a byproduct of natural gas production.

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[1] Oil: Possible Levels of Future Production; Federal Energy Administration, Project Independence Blueprint Final Task Force Report; November, 1974.

Recovery of heavy oil and tar sands hinges on lowering the viscosity of the oil either by solvents or the application of heat. The SolFrac process,[2] developed by the Interior Department's Bureau of Mines, has possibilities for application to shallow sandstone reservoirs of heavy oil. The method consists of formation fracturing with chemical explosives, followed by the introduction of a solvent and subsequent recovery of the oil entrained in the solvent. A second solvent method, cyclic solvent injection, has the potential for increasing the recovery from producing reservoirs of heavy oil. Basically, the cyclic method involves injecting a solvent into a well producing heavy oil, and, after a soak period, returning the well to production. However, as we discussed in the last Chapter, the economic viability of solvent methods hinge critically on the ability to recover and recycle the solvent.

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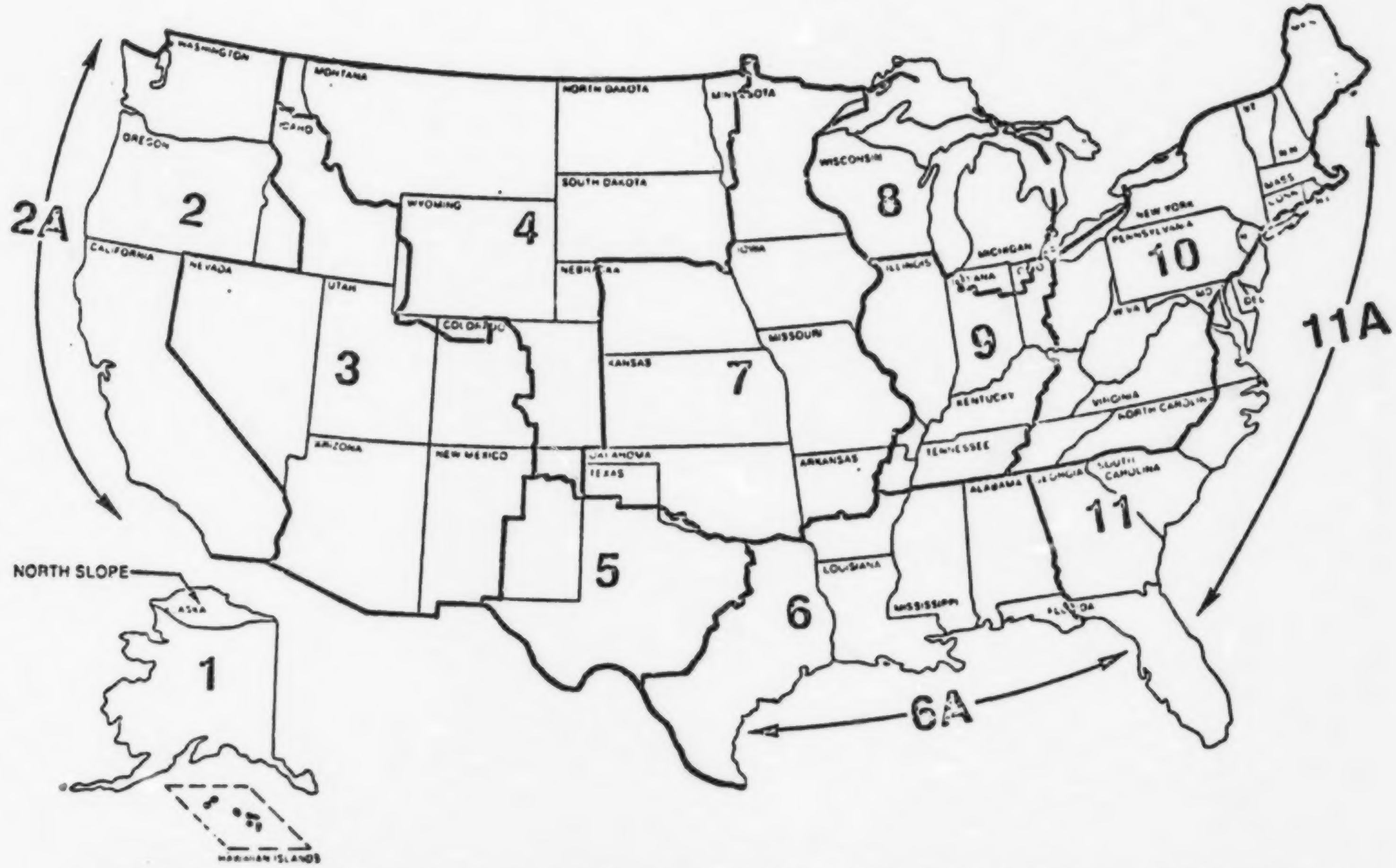
[1] Five-Year R&D Programs, U.S. Department of Interior, Washington, D.C.;June, 1974.

[2] See our discussion in Chapter IV.

FIGURE V-14

NPC DOMESTIC PETROLEUM PROVINCES


2A
2
3
4
5
6
6A
7
8
9
10
11
11A
1
NORTH SLOPE
WASHINGTON
OREGON
CALIFORNIA
IDAHO
NEVADA
MONTANA
UTAH
ARIZONA
WYOMING
COLORADO
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
MICHIGAN
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
W VA
PENNSYLVANIA
NEW YORK
MD
DEL
VT
NH
MASS
CONN
RI
HAWAIIAN ISLANDS

Regional Boundaries: Region 1—Alaska and Hawaii, except North Slope; Region 2—Pacific Coast States; Region 2A—Pacific Ocean, except Alaska; Region 3—Western Rocky Mountains; Region 4—Eastern Rocky Mountains; Region 5—West Texas and Eastern New Mexico; Region 6—Western Gulf Basin, Region 6A—Gulf of Mexico; Region 7—Midcontinent; Region 8—Michigan Basin; Region 9—Eastern Interior; Region 10—Appalachians, Region 11—Atlantic Coast; Region 11A—Atlantic Ocean.

Source: NPC, *Future Petroleum Provinces of the United States* (July 1970)—with slight modification.

FIGURE V-15

SCHEDULE OF SECONDARY AND TERTIARY RECOVERY APPRECIATION FACTORS

(Business-as-Usual Scenario)

Region	Primary recovery	Delay (Years)	Secondary % New *	Secondary % Old+	Tertiary % New *	Tertiary % Old+
1	23	5	0	4.40	0	0
		10	11.5	3	0	0
		15	11.5	0	0	0
2	23.3	5	0	0.6	0	0.55
		10	13.3	0.72	4.05	1.70
		15	8.1	0.6	5.55	1.11
2A	23.3	5	0	0.5	0	0
		10	0.8	1.2	0	0.75
		15	1.16	2.40	0.81	0.75
3	22	5	0	1.5	0	0
		10	7.3	1.2	0	0
		15	7.3	0.48	0	0.15
4	24	5	0	1.5	0	0.5
		10	6.9	1.2	1.50	0.75
		15	5.86	0.6	3.51	0.75
5	20	5	0	1.5	0	1
		10	10	1.2	7.50	2.25
		15	4.5	0.6	6.75	3
6	46.5	5	0	1.5	0	0.0
		10	1.5	2.70	0.45	1.5
		15	0.45	3.60	0.225	3
6A	47.6	5	0	0.45	0	0
		10	1.62	0.88	0	0
		15	1.62	1.45	0	0
7	25	0; 5	9.0	1.5	1.0	0.1
		16;16	8.0	1.35	3.0	0.45
		-; -	6.0	0.94	6.0	0.75
8,9,10	27.4	5	0	0.6	0	0.05
		10	8.45	0.57	0.427	0.35
		15	5.57	0.37	1.98	0.559
11	33	5	0	0	0	0
		10	3.3	0	0	0
		15	0	0	0	0
11A	33	5	0	0	0	0
		10	1.62	0	0	0
		15	1.62	0	0	0

* New fields after January 1, 1974. (Percent applied one time to annual oil-in-place discovered per time delay)

+ Old fields prior to 1974. (Percent per year applied to cumulative oil-in-place on January 1, 1974)

Source: FEA, Project Independence Blueprint

FIGURE V-16

CONSTRAINTS TO SECONDARY AND TERTIARY RECOVERY PRODUCTION

For all regions, except 6 and 6A,

a) primary + secondary recovery $\leq$ 50%,

b) tertiary recovery = 0 if (primary + secondary recovery) = 50%.

For regions 6 and 6A:

c) primary + secondary recovery $\leq$ 60%,

d) tertiary recovery = 0 if (primary + secondary recovery) = 60%

For "old" oil, all regions,

e) secondary recovery $\leq$ 0.75 x primary recovery

For "new" oil, all regions,

f) secondary recovery $\leq$ primary recovery

Source: FEA, Project Independence Blueprint

FIGURE V-17

SECONDARY AND TERTIARY INVESTMENTS ASSUMPTIONS

	$ per bb of reserve added	
	1974	1988
Secondary projects		
Region 1	0.96	1.92
Regions 2A, 6A, and 11A	0.64	1.28
Regions 2, 3-6, and 7-11	0.32	0.96
Tertiary projects		
Region 1	1.68	3.12
Region 2	1.50	3.00
Regions 2A, 6A, and 11A	1.12	2.14
Regions 3-6, 7-11	0.80	1.76

Source: FEA, Project Independence Blueprint

FIGURE V-18

PROJECT INDEPENDENCE BLUEPRINT ANALYSIS OF RECOVERY[*] SENSITIVITY TO PRICE CHANGE: WEST TEXAS (5), WESTERN GULF BASIN (6) AND GULF OF MEXICO (6A)

	REGION	1977				1980				1985				1988			
		MAP	$4	$7	$11	MAP	$4	$7	$11	MAP	$4	$7	$11	MAP	$4	$7	$11
New Field Primary and Secondary Production	5	$8.29[**]	1836	1888	2069	$9.20	1573	1610	2078	$11.18	1196	1218	2334	$11.70	972	987	2493
	6	$6.31	1868	1888	2069	$6.85	1603	1959	2037	$ 7.77	1516	2084	2514	$ 8.71	1575	2144	2951
	6-A	$3.11	981	981	981	$3.71	1147	1147	1147	$ 4.50	1548	1548	1548	$ 5.36	1489	1489	1489
Tertiary Production	5	$8.43	1836	1888	2069	$9.29	1573	1610	2078	$11.04	1196	1218	2334	$12.09	972	987	2493
	6	$8.09	1868	2069	2069	$8.81	1603	1959	2037	$10.05	1516	2084	2514	$10.95	1575	2144	2951

[*] All volumes in MMBBLS/Day.

[**] The dollar value preceding each year's production volumes represent "minimum acceptable price" under FEA's "baseline scenario".

Source: FEA, Project Independence Blueprint

Final Comments

The foregoing evaluation is obviously preliminary and involves a good deal of quantitative analysis tempered by our best judgment in many instances. A complete analysis would involve an explicit application of the various enhanced recovery methods to each of the major domestic reservoirs, simulating the response of these reservoirs to these methods, assessing the economics and deriving the marginal cost curve for each reservoir. These individual marginal cost curves could then be aggregated into the domestic supply curve. Such an undertaking would require considerably more resources than were brought to bear in this study as well as reservoir data that are not yet available. We would be among the first to admit that the time and resource costs of performing such a detailed analysis could far outweigh the benefit of additional insights gained though for some fields this "micro-level" of detail appears justifiable.

Of equal importance to the conclusions presented above are the implications our study bears not only on the environmental problems associated with alternatives to conventional oil production, but to the changes in the level and distribution of national income associated with domestic crude price deregulation alternatives. Most important, however, may be the implied prospect for displaying an elastic import demand curve to the OPEC cartel, thereby putting downward pressure on OPEC prices which have fueled the dual inflationary and recessionary pressures currently plaguing our nation.

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APPENDIX A

INTERVIEW AND FIELD TRIP SUMMARIES

PERSONAL AND ORGANIZATIONAL CONTACTS

NOTE

On the following pages are concise profiles of interviews and visits conducted with numerous industry, trade association, government and academic contacts whose organizations represent potentially valuable sources of pertinent information and data. Where available names, addresses and telephone numbers are provided so as to facilitate future follow-up activities if warranted. These organizations include:

(1) U.S. Bureau of Mines
(2) U.S. Geological Survey
(3) U.S. Federal Power Commission
(4) Texas Railroad Commission
(5) Louisiana State Department of Conservation, Oil and Gas Division
(6) California State Department of Conservation, Oil and Gas Division
(7) Interstate Oil Compact Commission
(8) International Oil Scouts Association
(9) Oil Law Records Corporation
(10) Oklahoma University
(11) American Petroleum Institute
(12) Petroleum Information Corporation
(13) The Oil and Gas Journal
(14) Texas State House Reporter
(15) AMOCO Production Company
(16) Standard Oil Company of California
(17) Tenneco Oil Company
(18) Getty Oil Company

Oklahoma University Research Institute

Contact: Mr. J.L. Morrision, Director of the Oklahoma University Research Institute's "GIPSY" data base and information systems project (405-325-7251); Dr. P. Root, Professor in Oklahoma's Department of Petroleum Geology. (Dr. Root formerly served for a period on the FPC staff during the conduct of the National Gas Survey). The Institute is located in Norman, Oklahoma.

Summary: Perhaps the most ambitious attempt to collect data on domestic United States reserviors is that being undertaken by the University of Oklahoma Research Institute under USGS sponsorship. Project persennel met with Mr. J.L. Morrison of the Research Institute and had several follow-up telephone conversations concerning the Oklahoma University data base. Essentially, Oklahoma's effort involves the collection and computerization of existing data bases compiled by state regulatory agencies. As such, it is variable in quality and suffers from whatever gaps exist in the state data. They have essentially no data relating to the OCS. Half the 65,000 reservoirs Oklahoma has data on are in Texas. Mr. Morrison felt that Mississippi was by far the best reporter of statistics with respect to reservoir characteristics. He agreed to furnish us with a copy of his Mississippi file together with instructions for accessing it.

The Oklahoma University data base is a well-designed variable record length file structure. We had no problem writing PL/1 programming for accessing this data and uncovered no discrepancies in the Mississippi file. Unfortunately, however, the data collected by Mississippi was found insufficient to support our analysis from the standpoint it lacked adequate reservoir data from which to estimate remaining oil in place as a function of depth, permeability, gravity, and current oil saturation. While the Oklahoma data dictionary is quite extensive and is set up to accept just about every reservoir descriptor imaginable, the actual Mississippi information is mostly "blanks". For most of the fields, there is considerable information on production history. Often data exists for gravity, porosity and permeability, sometimes initial pressure, but rarely current pressure, thereby invalidating any attempt at initial petroleum in place estimation via mass balance.

Another problem is that when acreage is reported, it is usually the acreage reported at discovery, which by API convention includes at most the spacing on which the wells already drilled are sited plus the offset locations. This acreage is typically a small proportion of the actual extent of the field. Thus, the reported reservoir acreage "grows" by extension and revision as additional wells are drilled. This problem of "growing acreage" is a severe obstacle to meaningful analysis. In the Mississippi case (as well as others, we suspect) the initial reported acreage apparently has not been revised. Thus, if one makes an estimate of OOIP on a volumetric basis from this data, one finds that often his estimate is less then the amount of oil already produced from this field.

In short, after examining the Mississippi file in some detail, we came to the conclusion that it would be impossible to estimate the initial oil and gas in place from the data for more than a handful of the over 1000 reservoirs listed. If Mississippi is the "best of the lot" as claimed, the Oklahoma data base in its present form cannot yet support recovery curve analysis. However, our feeling is that the Oklahoma effort is well designed and what is required is a selective effort to fill in the key blanks starting with the largest fields and working down. At a minimum, what is required is sufficient data to estimate the original oil-in-place from mass balance or simple volumetric considerations (area, average net pay, porosity, initial oil saturation) and data on current oil saturation.

Dr. Root was contacted after we learned in conversations with staff in the Washington offices of the National Petrolum Council (202-393-6100) that Oklahoma University had been given a complete package of computer programs, data, working papers and other materials used by the NPC Oil and Gas Supply Task Groups in their preparation of the Oil and Gas Availability volume of the U.S. Energy Outlook report. Unfortunately, Dr. Root had not been able as yet to wade through much of this material, was not sure what he did or did not have, and in general could not amplify further upon any of the documentation dealing with enhanced oil recovery already presented in the NPC's published reports.

AMOCO Production Company

Contact: Mr. L.E. Elkins (918-581-3011) Production Research Director with AMOCO and Chairman of the NPC's Oil Supply Task Group which performed the oil supply analysis reported in the Oil and Gas Availability volume of the U.S. Energy Outlook report. Mr. Elkins is located in Tulsa, Oklahoma.

Summary: Mr. Elkins explained that there does not really exist much more in the way of "back-up" material specifically regarding the oil recovery analysis presented in the NPC report. The evaluation did not rely upon any in-depth data analysis or modelling activity. Rather, it was more of a "round-table" concensus of "expert" opinion of geologists and engineers with extensive experience in oil recovery projects. The "recovery appreciation" factors developed in the report were then applied in a straight-forward "accounting-like" manner in order to determine enhanced recovery's contribution to future supplies.

Elkins stated that much quantitative modelling is being conducted by the industry including many of the companies represented by members in the Oil Supply Task Group. For instance, Mr. Elkins is aware of at least thirteen reservoir models being used by companies to examine the feasibility of micellar polymer injection techniques, all of which, of course, are proprietary and many of which to his thinking provide highly conflicting results.

American Petroleum Institute

Contact: Mr. J. E. Hodges (202-833-5576) Director of Petroleum Statistics at API. API is located in Washington, D.C.

Summary: We spoke with Mr. Hodges concerning the possibility of obtaining field and reservoir data from the Institute at a disaggregated level of detail provided such disaggregation would present no conflict with confidentiality or proprietary disclosure.

Hodges proceeded to describe what he termed "the myth" that API is cloistering significant amounts of detailed industry data which it does not publish at all or which it "masks" in highly aggregated form.

The interface with detailed field and reservoir statistics occurs within the internal workings of API's Committee on Petroleum Reserves, of which Hodges is Secretary.

The Committee is organized as follows: Each member of the Committee (except the Secretary) appoints one or more subcommittees for the purpose of preparing reserves and productive capacity estimates for his area of responsibility. The Subcommittees, which are responsible for determining annual reserves and productive capacity estimates are composed of geologists and engineers who (1) represent various segments of the producing industry having prominent ownership holdings in the Subcommittee's assigned area; (2) have broad experience in the estimation of reserves and productive capacity; and (3) have an intimate knowledge of the areas and the larger sized fields assigned to them. The Subcommittees make multiple assignments of selected fields to their members where it is felt that this will beneficially contribute to the quality of reserve and productive capacity estimates and promote the exchange of expert views.

The Committee on Reserves operates under the API policy on petroleum statistics which espouses the following:

> "Statistical information is published under Institute sponsorship in the maximum degree of detail consistent with the safeguarding of proprietary information of individual companies, while mindful of the cost and utility of the data involved. The Institute's statistics are confined to current and historical data. The Institute does not participate in the publication of forecasts of future demand for petroleum or its products, not of estimates of crude oil, natural gas liquids recoveries that are speculative in nature or that rely upon conjecture regarding future physical or economic conditions."

To assure continued cooperation of its subcommittee members, the committee adheres to the firm policy of maintaining strict confidence with respect to basic data and estimates of reserves and productive capacity for individual fields. No member of the committee or its subcommittees is authorized to make available to anyone outside the committee organization any information beyond that which is published in API reports. It is Hodges further contention that subcommittee members retain their work-sheets and back-up data and only submit to API through the Committee information already in an aggreagted form.

U.S. Geological Survey (Washington, D.C.)

Contact: Mr. R. Horton, Petroleum Engineer and Geologist with U.S.G.S. (703-860-7524).

Summary: Mr. Horton explained that U.S.G.S. simply is not involved with the collection or maintenance of data for public dissemination pertaining to the operations of active oil and gas fields, *per se*. In conjunction with their continuing interest in the domestic resource base, U.S.G.S. has just recently, for example, published independent estimates of proved and indicated-inferred reserves as well as undiscovered recoverable natural gas resources which correspond to the Potential Gas Committee's "probable", "possible", and "speculative" gas estimates. However, for our purposes, U.S.G.S. does not appear to be a potential source of data for active fields and reservoirs.

U.S. Geological Survey (Metaire, Louisiana)

Summary: Conversations with USGS personnel in New Orleans revealed that available computerized data was limited to oil and gas production (actually monthly sales which can differ from production by fluctuations in inventory) by month and lease. The agency also has copies of all well logs but this is not public information. Up until very recently, the USGS has made no attempt to systematically gather data on the characteristics of OCS reservoirs. MER's and MPR's appear to have been set in almost complete ignorance of reservoir characteristics, on pseudo-economic grounds (depth of formation and depth of water, neither of which variables has anything to do with reservoir producing capability) which represent something of a throwback to proration days. Occasionally, for specific unitization proceedings or drainage sales, rather detailed reservoir analysis is undertaken. However, this is the rare exception rather than the rule.

This situation appears about to be changed. Under a modified OCS Order 11, all operators will be asked to fill out a reservoir characteristics questionnaire. This form asks the right questions for MER and MPR decisions and the information would support and be quite valuable for recovery curve analysis. However, while the Geological Survey intends to computerize the responses, the information will not be made public on the grounds that it is proprietary. There appears to be somewhat of a contradiction in the Survey's spending several hundred thousand dollars and considerable effort to obtain reservoir data on on-shore fields which they make public and then classifying the same data to be gathered on O.C.S. fields as proprietary. If it is in the general interest to make the data on on-shore fields public, why is the same interest not equally served by public off-shore data? The counter argument for holding O.C.S. reservoir data proprietary is that the leasee has a competitive advantage with regard to unleased neighboring tracts. This is true but the rebuttal is why should the public offer this advantage to these particular leasees when such practice clearly seems to depress bonus bids on the neighboring tract when it is leased?

These issues notwithstanding, as of right now, USGS OCS data bases are essentially nonexistent and cannot support our current analysis. In the future, the data collected under OCS 11 would support such analysis. However, at present it does not appear that it will be made publically available.

Louisiana State Department of Conservation, Oil and Gas Division *(Baton Rouge, Louisiana)*

Contact: Mr. J. Hecker, Chief Engineer (504-389-5161).

Summary: We were informed that the Division publishes a yearly summary of secondary and tertiary recovery projects in the State (the last available issue being 1972). A copy of the latest volume was sent to us by mail. The report contains not only the general information included in a counterpart publication by the Texas Railroad Commission (TRC), but also some data on oil-in-place, residual oil saturation, and other important parameters, though unfortunately there are numerous gaps. Nonetheless the documents are a valuable addition to our information files.

U.S. Bureau of Mines (Bartlesville, Oklahoma)

Summary: We visited the Bureau of Mines, Improved Recovery Laboratory in Bartlesville, mainly to obtain information on tertiary recovery methods. However, much time was spent browsing through their library. It appears from the contents of this library that if one had the time and patience, he could track down the major characteristics of every large field in the United States. If it's a big field, it has very likely been written up somewhere.

It is important to remember that, while there are some 60,000 petroleum reservoirs in the United States, less than 300 of these fields account for about 60% of the production. Our analysis of Texas fields indicates that approximately 250 fields account for 80% of Texas production. Therefore (as described in Chapter III) we decided that perhaps the most fruitful approach would be to go after the largest 250 to 500 fields. Such fields represent about 75% of current production and with the addition of a few large heavy oil deposits, very likely that proportion of the tertiary prospects as well.

Texas Railroad Commission (Austin, Texas)

Summary: As part of this project, two trips were made to the headquarters of the Texas Railroad Commission and four man-days were spent perusing the Commission's files. These files cover some 30,000 Texas reservoirs and consist mainly of transcripts of hearings to determine MER's applications and supporting documents relevant to fluid injection projects. Needless to say, the material is quite voluminous. The files are open to the public and the staff is accustomed to serving consultant and lawyer inquiry. At times, the documents, particularly the technical analyses supporting fluid injection applications, contain valuable bits of reservoir characteristics and injection project cost data. However, this data is interspersed among reams of trivial bookkeeping, and access is a tedious and thankless business. The procedure is particularly difficult with respect to the important, very large fields due to the fact that the individual hearing records pertain to particular units. A very large field may be divided into as many as thirty units. Thus, it is difficult to ascertain what is happening to the reservoir as a whole from any particular portion of the records. Only bits and pieces of this data have been computerized including a listing of reinjection projects and annual production data.

Fortunately, most of what can usefully be gleaned from the TRC records is available in a much more convenient form. These are two annual publications of a private firm known as the Texas State House Reporter:

(i) MER Hearing Summaries [26]

(ii) Secondary Recovery Railroad Commission Application Summaries. [27]

These publications contain paragraph-length synopses of each hearing; these synopses contain almost all the reservoir data, claims for recovery, and overall cost figures presented by the litigants and applicants.

Using this information in conjunction with other data sources, we believe it is possible to estimate remaining oil in place for most of the large fields in Texas.

Oil and Gas Journal (Tulsa, Oklahoma)

Contact: Mr. W. B. Bleakley, Editor of Production for the Journal (918-584-4411).

Summary: Mr. Bleakley indicated that relative to field and reservoir characteristics data, the Journal, through its Annual Forecast Reviews and International Encyclopedia of the Petroleum Industry, publishes all information to which it has access. The Journal neither collects nor maintains any other proprietary data. In short, if it cannot be published, it is of no use to the Journal.

From time to time articles appear in the Journal which contain proprietary industry cost and performance data voluntarily disclosed by the author and his company. However, the Journal does not have the capacity to search or retrieve articles by either topic or keyword via any automated system in order to provide a pertinent reference list for our purposes. Mr. Bleakley expressed his feeling that detailed reservoir information of the sort we desire has appeared in Journal articles, but on a rather irregular and infrequent basis.

Interstate Oil Compact Commission (Oklahoma City, Oklahoma)

Contact: Mr. C. E. Bowlin, Director of the Commission's Technical Services Staff (405-525-3556).

Summary: Mr. Bowlin described the Commission's activities and indicated that its primary role is educational and administrative in nature and pertains to oil and gas conservation. The Commission essentially coordinates information exchange among the individual state regulatory agencies and publishes materials dealing with conservation topics. The Commission had, at the time of our initial contact, no direct access to data or information such as what we might require. We did receive from the Commission some technical documentation concerning advanced recovery research conducted under its auspices.

However, in late 1974, the Commission under FEA Contract C-05-50130-00 performed a most comprehensive survey of enhanced recovery operators, primarily to ascertain the impact upon enhanced recovery investment of lifting the prevailing FEA two-tier oil price regulation policy.

During the period of December 1974 through January 1975, the Interstate Oil Compact Commission and the regulatory bodies of the compacting states collected a comprehensive data base on existing and projected enhanced recovery activities. Responses were received from over 900 operators of enhanced recovery projects in 30 compacting states, with individual data collected on over 4300 existing projects.

These responses represented over 49% of the 1973 domestic enhanced production. On a state-by-state basis, statistically valid responses were received from 28 of the 30 compacting states. These twenty-eight states produced more than 98% of the crude oil recovered by existing enhanced recovery projects in 1973.

The data collected by the Interstate Oil Compact Commission and the compacting states' regulatory bodies was compiled into a computer data base. This information was projected on a state-by-state basis, based on the percentage of 1973 enhanced production represented by the respondent replies for that state.

This data clearly represents a major contribution to the assessment of enhanced recovery prospects. Though not available in time to be incorporated into our study, it is hoped that these data will be made accessible to researchers by the Commission for future studies in this area.

California State Department of Conservation, Oil and Gas Division (Sacramento, California)

Contacts: Messrs. R. Rothermel, Chief Engineer and J.F. Matthews, State Supervisor of Oil and Gas (916-445-9686).

Summary: In a series of telephone conversations we were told that California has a strict Public Resources Code which prohibits access by the public to information and data submitted in confidence to a public agency such as the Department of Conservation unless the agency, itself, reports the data in a form suitably aggregated to prevent adverse individual disclosure.

Though there are compulsory laws which require operators to gain approval of the Division before beginning enhanced recovery projects as well as mandatory unitization statutes, most of these matters receive somewhat perfunctory treatment by the Division. Public hearings are not held; most all unitization proceeds voluntarily without dissenting minority objections, and little or no data are submitted to the Division by either the operators or their consultants in these applications.

Mr. Matthews explained that these procedural requirements are being significantly revised. In addition to the currently published Summary of Operations (see Bibliography), the Division will soon publish a detailed reserves report which will be tied to an independent validation by the State of reported reserve inventories by the individual operators. Data collected in conjunction with this and other new undertakings by the Division will be computerized in data banks from the outset, thus facilitating the retrieval and reporting functions.

Mr. Matthews indicated the Division would like to be of help to us and suggested that if we could indicate specific reservoirs, fields, or projects of interest, he would try to have his staff use the influence of the Division to get the information from the operators. Due to staff limitations, he made it clear that his office could only accomodate a modest number of such requests from us.

In January 1975 we requested the help of the Division in arranging a series of field visits with operators of thermal recovery projects in the San Joachin Valley area. Through the Division's effective liaison we were able to arrange personal meetings with the following organizations and individuals:

Getty Oil Company
Route 1
Box 197-X
Bakersfield,
California 93308
(805)399-2961

Charles G. Bursell
San Joaquin Valley
District Engineer

T. J. Hurst
Lead Staff Engineer
San Joaquin Valley District

Tenneco Oil Company
Post Office Box 1996
Bakersfield,
California 93303
(805)832-9010

Robert Douglass
District Production Engineer

Standard Oil Company of
California,
Western Operations, Inc.
225 Bush Street
San Francisco,
California 94104
(415)894-0966

J. M. Miller
Supervising Engineer -
Petroleum
Reservior and Production
Producing Department

W. G. Paulsell
Senior Staff Engineer -
Reservoir
Reservior and Production
Producing Department

W. D. Edman
Staff Engineer Reservoir
Engineering Petroleum
Producing Department

Some very excellent detailed information was obtained in these interviews relating to:

(i) Initial costs of components (steam generators, piping, injection wells, etc.);

(ii) Operating costs (especially maintenance, separation, and water treatment); and

(iii) Effectiveness as a function of permeability, viscosity, formation thickness, well spacing, etc.

This information helped to "plug gaps" in our information concerning thermal projects in general, and steam recovery, in particular, and is reflected in the discussions given in Chapter IV.

International Oil Scouts Association

Summary: The International Oil Scouts Association publishes an annual which summarizes new discoveries and production by field. The current volumes also give discovery year, depth, thickness, formation name, API gravity, and number of wells. Prior to 1961, the annuals also contained type of structure, rock type, and occasionally production mechanism, porosity, permeability, and proved acreage. Discussion with Oil Scouts personnel indicated that the additional information was dropped due to expense. Still, this source remains the most extensive source for those reservoir characteristics which tend to remain stable (everything but acreage and thickness). Unfortunately, the Oil Scouts data is insufficient to estimate original oil-in-place.

Petroleum Information Corporation (New Orleans, Louisiana)

Contacts: Messrs. J. Hupp and J. Hendricks in PIC's Technical Applications Staff (504-525-1364).

Summary: After describing what information we needed, we were informed that PIC simply does not have such data in compiled form because, in the company's opinion, this information would have little commercial value, rendering the associated data collection and validation effort disproportionately costly. We were told also that should we feel we could profit from PIC's experience and general facility in petroleum data gathering, the company would consider a cost plus type retainer to gather whatever information might be available for fields and projects of interest.

Mr. Hupp indicated that PIC would probably not contact individual operators, companies, or other privileged sources to which we might be denied access. Rather any benefit to us would accrue from the thoroughness, efficiency, and timeliness with which they could search out these sources. We chose not to reach for our checkbook.

Oil-Law Records Corporation (Oklahoma City, Oklahoma)

Contact: Mr. P. M. Peterson, Officer of the Oil-Law Records Corporation (405-528-4559).

Summary: This firm specializes in oil and gas regulation matters. The firm does not have in its own files ready access to information such as we required, but did nonetheless, supply us with some interesting information. The Oklahoma Division of Oil and Gas Conservation, until the early 1950s kept detailed records of unitization hearings which were conducted under the State's statutes. However, since that time, almost all unitization has proceeded on a voluntary basis and thus have not come under the purview of the State. Most of these early records have since been lost or destroyed. Oklahoma does have a compulsory law which deals with well spacing and field development configuration. However, the hearing's data comprises more of an "exception file" in that it primarily contains information on fields and projects which require special dispensation for not conforming to these standard criteria.

Mr. Peterson also mentioned that the Dowell Division of Dow Chemical Company of Dallas, Texas, approached his firm about fifteen years ago to obtain data dealing with actual versus predicted recovery (primary and secondary) from fields in Oklahoma. Their effort was also to have included similar data gathering for Texas and was aimed at uncovering lease operators whose projects might be "in trouble" and thus in need of Dowell's services and products. In speaking with Mr. R. E. Hurst of Dowell (Houston office: 713-224-1315), he expressed total lack of knowledge of the effort and claimed that if such a project had ever been undertaken in the last twenty years, it would certainly have come under his purview. Since Mr. Peterson no longer has his project files on that effort, this "lead" appears to have hit a dead end.

U.S. Federal Power Commission

Summary: The Federal Power Commission requires all interstate gas operators to report annually on their operations by reservoir. This data contains, among other things, gas production by reservoir, estimated reserves, and depth. In order to examine the usefulness of this source, we obtained copies of these "Form 15" tapes for 1971 and 1972. In a word, these tapes are useless for supply curve purposes.

The tape is merely a straight running transcription of the Form 15 responses onto cards. There is essentially no data set design or structure. The same variables show up in different places in different reservoirs. Misspellings and mispunchings are common. Both tapes were in physically poor condition. The

1971 tape, after being accessed three times, could no longer be read, despite the rather sophisticated recovery mechanisms available at the M.I.T. Computer Center. The 1972 tape never ran at all. There is no description of such key reservoir variables as permeability, and any reservoirs not involved in interstate sales are omitted entirely. Thus, these tapes are not a valuable data source for our purposes.

APPENDIX B

WATERFLOOD PERFORMANCE MODEL

TWO-PHASE, TWO-DIMENSIONAL RESERVOIR FLOW COMPUTATIONS

R. J. STEWART

BACKGROUND

This model has been developed to allow us both to gain experience with the practical aspects of handling complicated systems of nonlinear equations and to provide a means of analyzing secondary oil recovery and various closely associated tertiary techniques. The physical system modeled includes two incompressible fluids flowing in two dimensions.The fluids exhibit an interfacial tension that leads to a capillary pressure correction that causes the two fluids to experience slightly different pressures (and pressure gradients) depending on the local saturations. The fluids may vary in density, and it should be possible to model the effects of gravity segregation.

The governing equations are derived from Darcy's law and the equation of continuity for each phase. They are written in differential form as follows:

$$(1) \quad -\nabla\cdot\left(\frac{K_{rw}}{\mu_w}\nabla'(P_N - P_c - \rho_w g D)\right) = -\phi\frac{\partial S_w}{\partial t} - q_p^W + q_i^W$$

$$(2) \quad -\nabla\cdot\left(\frac{K_{rw}}{\mu_N}\nabla'(P_N - \rho_N g D)\right) = \phi\frac{\partial S_w}{\partial t} - q_p^N + q_i^N$$

Where the subscripts W and N refer to the wetting and non wetting phases, respectively.

The equations are nonlinear because P_c, k_{rw}, and K_{rn} are functions of S_w, which is one of the two dependent variables in this system. The q's are production and injection volume rates, and P_G is the capillary pressure. ∇' is a modified gradient operator. It allows us to account for the non-isotropy in the premeability. It is written as follows:

$$\nabla' = K_x \frac{\partial}{\partial x} \underline{i} + K_y \frac{\partial}{\partial y} \underline{j} + \left[K_z \frac{\partial}{\partial z} \underline{j} \right] \quad \longleftarrow \text{3 - DIM TERM} \tag{3}$$

D is a potential of the form,

$$D = x \sin\alpha + y \cos\alpha \qquad \text{(2-Dim Form)} \tag{4}$$

This factor allows us to subtract out the hydrostatic portion of the pressure. P_N is the pressure experienced in the non-wetting phase. It is the second dependent variable. The independent variables in this system are time and spatial position ([x,y] in artesian coordinates, as used in the definition of ∇')

The form of the equations used in the finite difference approximation are as shown on the following page. The indices $\pm\frac{1}{2}$ indicate boundaries lying between volume elements. The MW and MN terms represent the mobilities which include the permeabilities, relative permeabilities and viscosity of the respective phases. The boundary terms are evaluated at the "upstream" element as determined by the local phase-specific pressure gradients. The solution technique is to treat each volume element's non-wetting pressure and wet-phase saturation as an unknown and solve for them implicitly. Thus a reservoir modeled as a (20 x 1) element array results in 40 unknowns (and forty equations). Likewise, a reservoir modeled as a (10 x 4) element array results in 80 equations and 80 unknowns.

The method employed to solve this system of equations is as follows: Treating the S_W^{n+1} and P_N^{n+1} values as unknowns (but the coefficients as knowns) the values of S_W^{n+1} and P_N^{n+1} are determined by solving the system using Gaussian Elimination. The coefficients are then re-evaluated using the

FINITE DIFFERENCE FORMULATION:

(5) Wetting Phase Equation:

$$- \Delta x \cdot T \cdot MW_{i-\frac{1}{2},j} \left[\frac{P_{i,j}^{n+1} - P_{i-1,j}^{n+1}}{\Delta y} - \rho_w g \cos\alpha - \left.\frac{dP_c}{dS_w}\right|_{i-\frac{1}{2},j} \cdot \frac{S_{w_{i,j}}^{n+1} - S_{w_{i-1,j}}^{n+1}}{\Delta y} \right]$$

$$+ \Delta x \cdot T \cdot MW_{i+\frac{1}{2},j} \left[\frac{P_{i+1,j}^{n+1} - P_{i,j}^{n+1}}{\Delta y} - \rho_w g \cos\alpha - \left.\frac{dP_c}{dS_w}\right|_{i+\frac{1}{2},j} \cdot \frac{S_{w_{i+1,j}}^{n+1} - S_{w_{i,j}}^{n+1}}{\Delta y} \right]$$

$$- \Delta y \cdot T \cdot MW_{i,j-\frac{1}{2}} \left[\frac{P_{i,j}^{n+1} - P_{i,j-1}^{n+1}}{\Delta x} - \rho_w g \sin\alpha - \left.\frac{dP_c}{dS_w}\right|_{i,j-\frac{1}{2}} \cdot \frac{S_{w_{i,j}}^{n+1} - S_{w_{i,j-1}}^{n+1}}{\Delta x} \right]$$

$$+ \Delta y \cdot T \cdot MW_{i,j+\frac{1}{2}} \left[\frac{P_{i,j+1}^{n+1} - P_{i,j}^{n+1}}{\Delta x} - \rho_w g \sin\alpha - \left.\frac{dP_c}{dS_w}\right|_{i,j+\frac{1}{2}} \cdot \frac{S_{w_{i,j+1}} - S_{w_{i,j}}}{\Delta x} \right]$$

$$= \Delta y \cdot \Delta x \cdot T \cdot \phi \, \frac{(S_{w_{i,j}}^{n+1} - S_{w_{i,j}}^{n})}{\Delta t} - q_w^i + q_w^p .$$

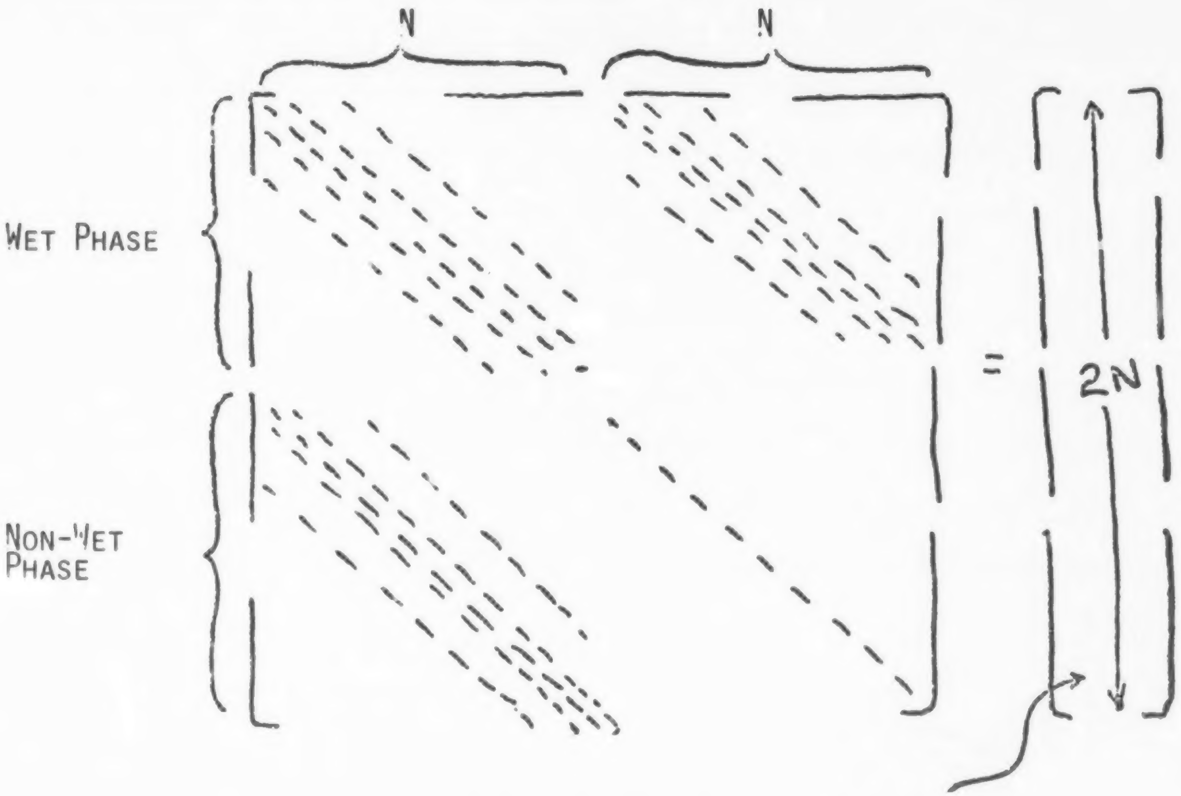
(6) Non-Wetting Phase Equation:

$$
\begin{aligned}
&- \Delta x \cdot T \cdot MN_{i-\frac{1}{2},j} \left[\frac{P_{i,j}^{n+1} - P_{i-1,j}^{n+1}}{\Delta y} - \rho_N g \cos\alpha \right] + \Delta x \cdot T \cdot MN_{i+\frac{1}{2},j} \times \\
&\times \left[\frac{P_{i+1}^{n+1} - P_{i,j}^{n+1}}{\Delta y} - \rho_N g \cos\alpha \right] - \Delta y \cdot T \cdot MN_{i,j-\frac{1}{2}} \left[\frac{P_{i,j}^{n+1} - P_{i,j-1}^{n+1}}{\Delta x} - \rho_g g \sin\alpha \right] \\
&+ \Delta y \cdot T \cdot MN_{i,j+\frac{1}{2}} \left[\frac{P_{i,j+1}^{n+1} - P_{i,j}^{n+1}}{\Delta x} - \rho_N g \sin\alpha \right] \\
&\qquad = \Delta y \cdot \Delta x \cdot T \cdot \phi \left(\frac{S_{w_{i,j}}^{n+1} - S_{w_{i,j}}^{n}}{\Delta t} \right) - q_N^{i} + q_N^{p}.
\end{aligned}
$$

the "updated" S_W^{n+1}. If the option 'iterate' is specified, the step is repeated using coefficients set at the average of the updated and initial values.

This particular method seems to work well enough, but we know it is very inefficient because the matrices we end up having to invert, are heavily banded, being mostly zeroes, Thus the bulk of the work performed in the Gaussian elimination step is composed of fruitless zero-multiplications. The matrices tend to have the following shape for a 2N system (N=20 for (20x1) array, N=40 for (10x4) array).

Determination of the Solution Vector:



Solution vector is composed of Hydrostatic Initial Sw's (Sw_i^n,;), and Production and Injection Rates.

The program essentially consists of four subroutines, one of which is the IBM SSP Gaussian elimination package MGB1. The other three are INTERPL, DERIVSW and INDXSW. INTERPL is a generalized linear interpolation routine. Its inputs include the indices of the bracketing tabulated values of the independent field variable used to determine values of the dependent field variable for which INTERPL was invoked. INDXSW is a subroutine that provides these indices. It also checks the values of the independent filed variable to assure that they are in bounds. If not, they are set at the appropriate extreme. DERIVSW is used to calculate the derivative of the tabulated function. This is achieved using a centered difference for values in the interior of the table. Values at the boundary of the table are determined by extrapolation from the interior.

Future improvements of this package will include subroutines to replace MSG1 with either a relaxation method solution technique, or perhaps a form of the alternating -direction- implicit method, or a technique involving alternating the dependent variables.

MODEL VALIDATION

Large complicated, generalized programs, such as the one described here, have one common feature, no matter what their original purpose. They are extremely hard to debug and they are harder yet to validate because suitable analytical solutions are usually not available for purposes of comparison. The modeler is therefore constrained to perform validations using either experimental data (physical analogs) or to simplify the system to the point where analytical solutions exist. In our application, analytical solutions exist for 1-dim. non-capillary reservoir flow. This is normally called the Buckley Leverette solution, but it is more appropriate to name it after Cardwell and his associates, for they provided the rigorous mathematical explanation of the method.

In one-dimension, the governing equations can be shown to be of the following form:

$$\frac{\partial S_w}{\partial t} + \frac{q}{A}\frac{1}{\phi}\frac{dF(S_w)}{dS_w}\frac{\partial S_w}{\partial x} = 0 \qquad (7)$$

where $F(S_W) = \frac{M_W}{M_N + M_W}$. Here we have set the capillary pressure term to zero. Given an initial saturation and an injection rate $q^{(+)}$, it is possible to construct solutions using the method of characteristics. The method is somewhat complicated by the possibility of the formation of shock fronts, but the details are well understood.

Using this method we have looked at the behavior of two reservoirs, 400 feet long, of 20 sq.ft. cross section, being driven by water injection at 1 Bbl/D (.003509 PV/D). One reservoir had an initial wet phase saturation of .456, while the other was initialized at .186. The time period investigated was 50 days after beginning the injection to 300 days after beginning injection. Earlier phases of injection are difficult to analyze due to the problem of physically interpretating the meaning of point sources.

Figure B-1

Reservoir Response Profile

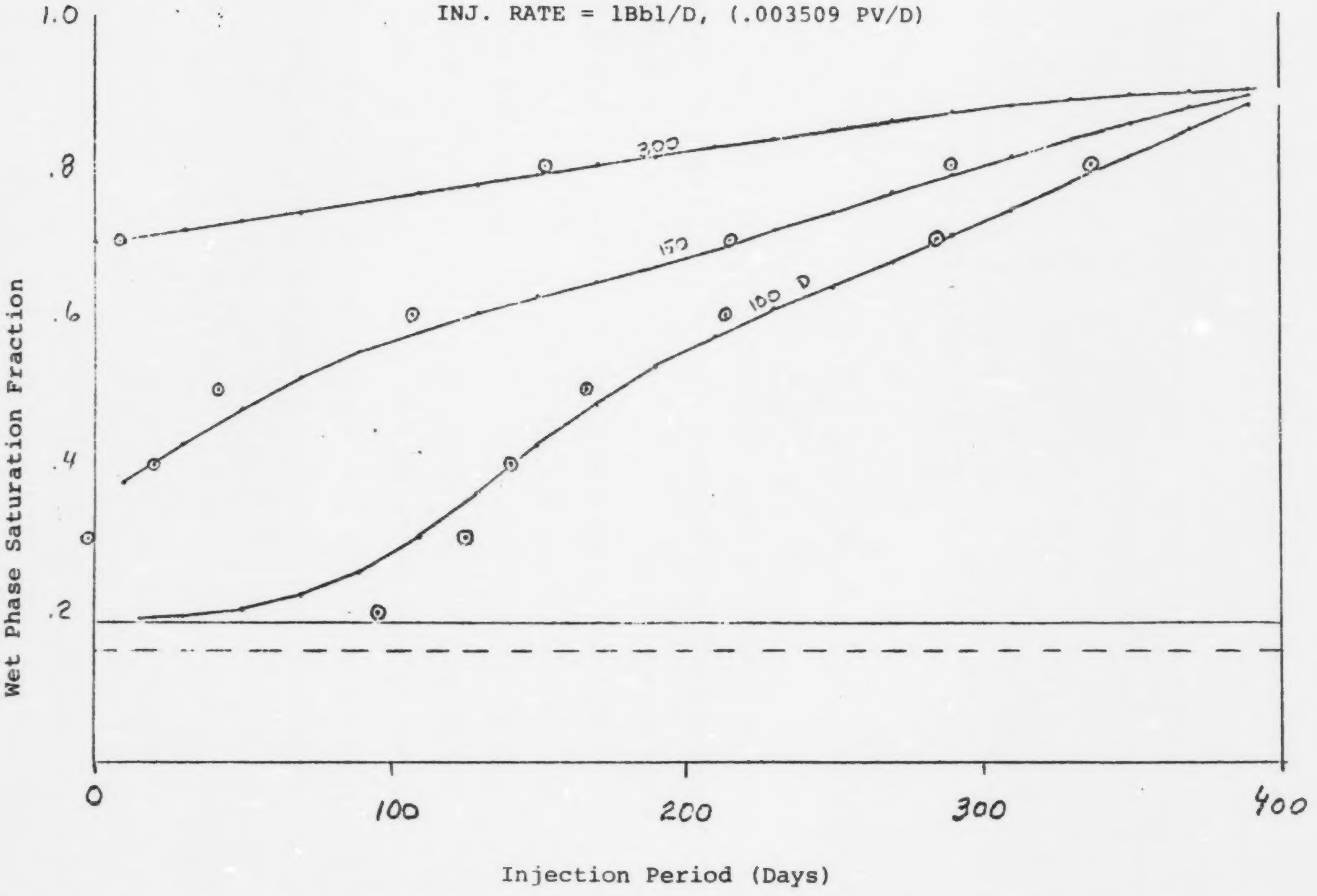
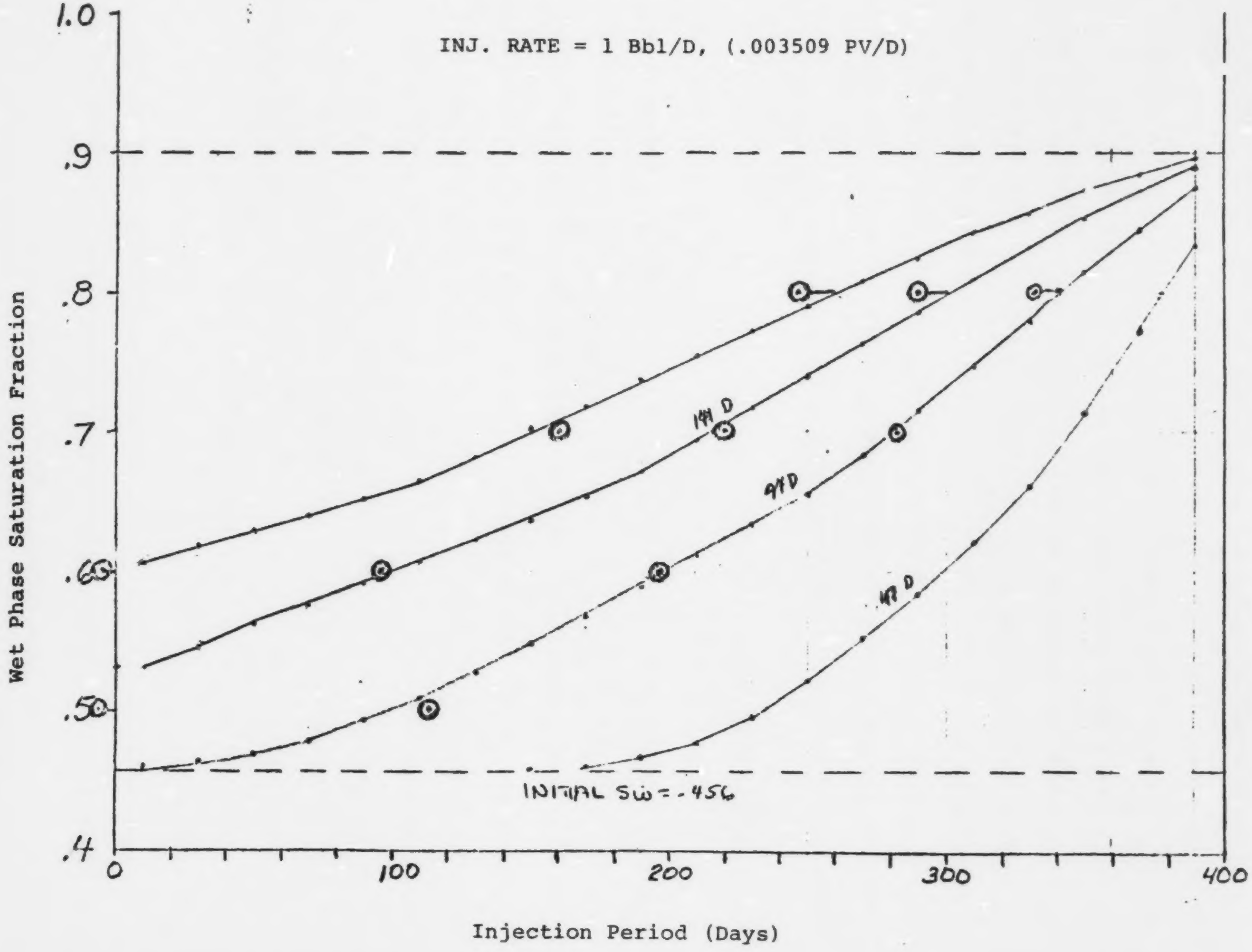

INJ. RATE = 1Bbl/D, (.003509 PV/D)

Figure B-2

Reservoir Response Profile



The program provided the saturation profile to be used at 50 days. Calculations after this relied solely on Q, A, ϕ, and dF/dS_W. The comparison was then made with the program's predictions. The comparisons are necessarilly somewhat indirect because we were forced to retain the capillary pressure in the computer simulation in order to avoid numerical problems associated with the shock front (the capillary pressure term prevents formation of a shock). However as we can see in Figures B-1 and B-2, agreement was reasonably good in the region of the shock front, and very good for long time behavior.

PRELIMINARY INVESTIGATIONS

The results obtained for the one dimensional system provide us with enough material so that we can foresee some rather interesting studies that can be made with the model. Since the model is of a fairly classical reservoir system, there is little doubt that almost any analysis we perform will already have a counterpart in the literature. Thus we do not anticipate that our results will in any way be particularly novel. However, they will constitute an independent validation of the rationale behind present industry practice, and this is of some value to policy makers.

The most concise display of the physical parameters governing the economics of water drive in any particular reservoir is the time history of the oil production (either rate of production or cumulative production) and the pressure increment required to produce the oil. Supplementing this information with the volume rate of injection, the cost of the injected fluid, and maintenance costs, we can calculate the costs associated with the day to day injection (the marginal cost). Coupling this with the initial cost of the separating and injection equipment, we can completly describe the cost side of the problem. Specification of the market price of the oil at the well-head completes the revenue side. A present value calculation can then be performed for any particular injection strategy.

The following two graphs in Figures B-3 and B-4 illustrate this point. They show the cumulative production (expressed here as a fraction of the original oil-in-place) and the instantaneous pressure required to drive 1 Bbl/day through the 1-dim. reservoir used in the validation.

Figure B-3

Fractional Recovery of Oil-in-Place
vs. Pore Volumes Injected

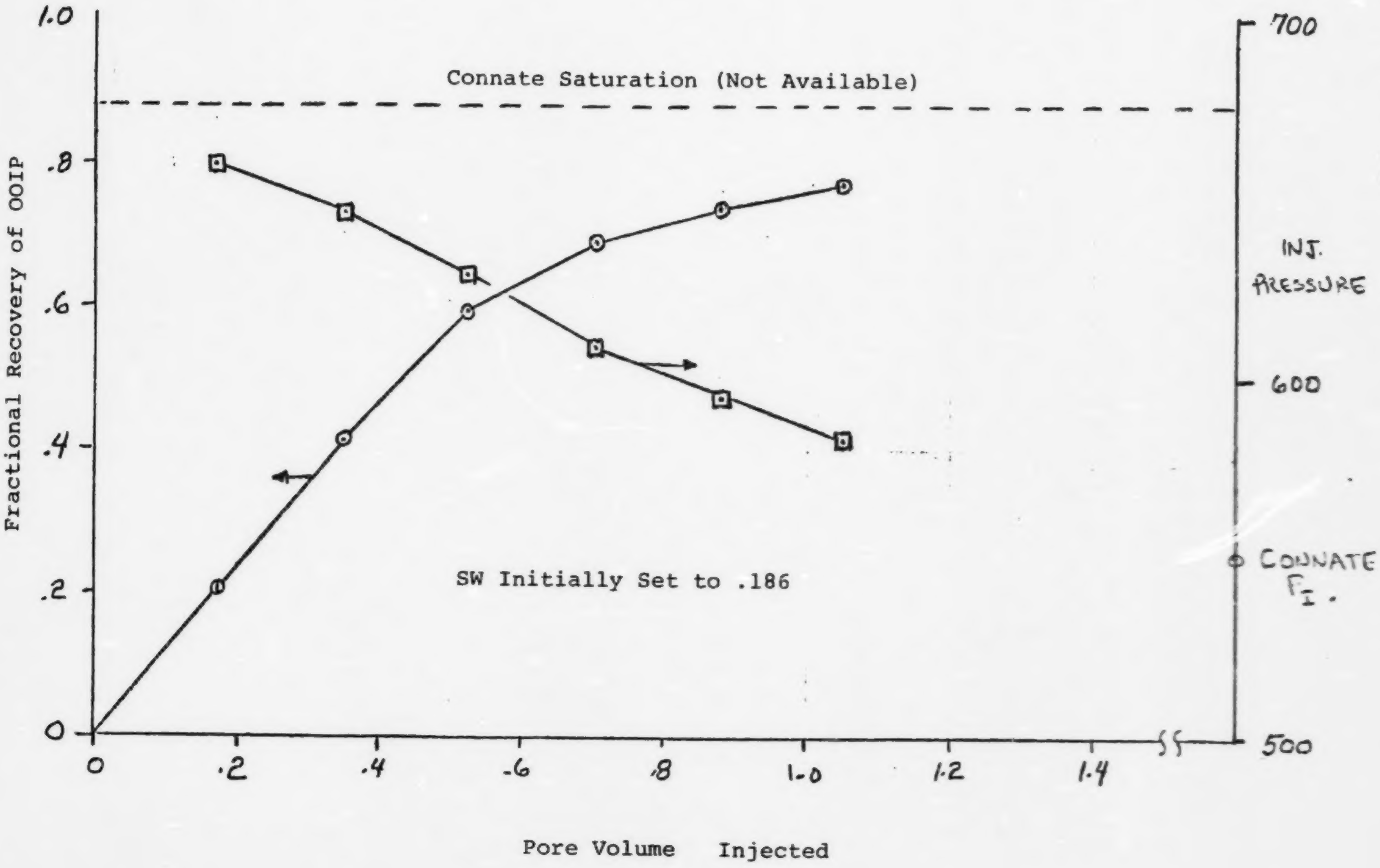


Figure B-4

Fractional Recovery of Oil-in-Place
vs. Pore Volumes Injected